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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

LEA MÁRQUEZ PETERSON, Chairwoman
SANDRA D. KENNEDY
JUSTIN OLSON
ANNA TOVAR
JIM O'CONNOR

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-22-0144 **APPLICATION**

In this Application, Arizona Public Service Company (APS or Company) seeks a net increase in base rates of $460 million, or 13.6%, to become effective on December 1, 2023.[1] The requested increase is necessary for APS to continue making the investments required to maintain a reliable, resilient, and clean energy grid for its customers today and into the future.

[1] APS submits this Application pursuant to Arizona Revised Statutes (A.R.S.) §§ 40-250 and -251, and Arizona Administrative Code (A.A.C.) R14-2-103.

APS's last rate case concluded on November 9, 2021 and was based on a test year that ended on June 30, 2019.[2] A variety of factors have changed since the conclusion of APS's last rate case, including significant investment in plant and infrastructure, revenue and expenses, the cost of capital, customer growth, compounded inflationary pressures, and disruptions to the global supply chain. Consequently, the Company's Application demonstrates a revenue deficiency of $772 million based on the 12-month period ending June 30, 2022 (Test Year). As such, the Company's current rates do not recover the necessary costs of providing electric service to customers today, let alone into the future. APS therefore seeks a rate increase to reflect these and other items based on the adjusted sales and expenses for the Company's jurisdictional electric operations that occurred during the Test Year.

APS is committed to continue making responsible and necessary investments to meet the needs of its customers by providing reliable, affordable, and clean energy. This rate case request is designed to achieve the following goals, all of which are critical to meet the needs and expectations of customers:

- Ensure reliability and resilience of the energy grid.
- Secure a clean, balanced energy supply for Arizona.
- Continuously improve support for customers.

Accordingly, APS requests an increase in net revenue of $460 million, or 13.6%, and to approve the rates, charges, and schedules set forth in this Application. This increase is necessary to meet the changing needs of our customers, sustain the financial stability of APS, and enable a more sustainable and clean energy future.

[2] Decision No. 78317 (November 9, 2021).

The Company's complete request is described in and supported by the testimony, exhibits, and schedules submitted with this Application. APS intends to call the following witnesses as part of its direct case, who will address the indicated topics:

Theodore N. Geisler	Rate Case Overview; APS Impact to Arizona; Customer-Focused Commitment; Revenue Requirement Preview; Importance of Stable Utility; Rate Increase; Customer Bill Impact; Adjustment Mechanism Proposals
Jacob Tetlow	Post-Test Year Plant; Operations and Reliability; Clean Energy Transition System Upgrades; Coal Community Transition (CCT)
Monica Whiting	Limited-Income Program Proposal; Payment Fee Removal; New Off-Peak Holidays; Customer Experience Improvements
Andrew Cooper	Utility Financial Stability; Relationship between Financial Stability, Return on Equity (ROE), Credit Rating, and Customer Impacts; Financial Implications of the APS Clean Energy Commitment; Importance of Adjustment Mechanisms and Reducing Regulatory Lag; Return on Fair Value Increment (FVI)
Justin M. Joiner	Resource Management; Planning and Procuring; Fuel and Purchased Power Expense; AG-X Program
Jessica E. Hobbick	Revenue Allocation; Adjustment Mechanism Proposal Details and Plans of Administration; Payment Fee, Limited-Income Discount, and Various Other Pro Formas; Standard Filing Requirements (SFR) H Schedules; Rate Design; Changes to Service Schedules and Programs/Riders; Elimination of Duplicative or Outdated Compliance Filings

Jamie R. Moe	Cost of Service Studies; Allocation of Production Capacity Costs; SFR Schedule A-1, All SFR G Schedules, and Portions of Other SFR Schedules; Fair Value Rate of Return Calculation; Base Fuel and Purchased Power Rate
Elizabeth A. Blankenship	Historical and Forecasted Accounting Information; Various SFRs and Pro Formas (Rate Base and Income Statement); Change to the Allocation of the Annual Nuclear Decommissioning Funding for Palo Verde Generating Station
Dr. Roger Morin, Outside Expert	Cost of Capital; Return on Equity; Fair Value Rate of Return

For convenience, APS includes as Attachment A an executive summary of each witness's direct testimony.

I. COMPONENTS OF THE RATE REQUEST

The requested rate increase is based on adjusted test year sales for the Company's jurisdictional electric operations during the Test Year. APS requests that the increase become effective on December 1, 2023. This date is consistent with the Commission's rule requiring it to process the Company's rate application within 12 months of the filing of a notice of sufficiency.[3]

A. Overall Rate Request

The net base rate increase proposed by APS is $460 million, which would increase the amount of net revenue APS currently collects from customers by 13.6%. Figure 1 below illustrates the Company's requested base rate increase and corresponding customer bill impact:

[3] A.A.C. R14-2-103(11)(d)(i).

Figure 1.

Overview of Rate Increase	Dollars	Bill Impact
Base Rate Increase		
Total Revenue Deficiency	$772M	22.9%
Test Year Adjustor Revenue Transfers	($108M)	(3.2%)
Base Rate Increase Net of Adjustors	$664M	19.7%
Net Rate Increase		
Day-One Power Supply Adjustment (PSA) and Renewable Energy Adjustment Charge (REAC) Changes	($204M)	(6.1%)
Day-One Net Rate Impact	**$460M**	**13.6%**

APS proposes its actual capital structure at the end of the Test Year, which was 51.93% equity and 48.07% long-term debt. APS's weighted cost of long-term debt at the end of the Test Year was 3.85%. As discussed by APS witness Dr. Roger Morin, APS proposes a return on equity of 10.25%, which appropriately reflects market risks and would permit APS to effectively compete for the capital it needs to continue investing in Arizona's energy future. Combined with the embedded 3.85% cost of debt, APS's weighted average cost of capital is 7.17%. The inclusion of a 1.0% return on the fair value increment (FVI) of the Company's fair value rate base produces a requested return of 4.92% on fair value rate base. This increment and the requested 1.0% return on the FVI have been calculated in a conservative manner and are consistent with past findings of the Commission in Decision Nos. 73183 (May 24, 2012) and 71448 (December 30, 2009).

1. Post-Test Year Plant (PTYP)

The base rate increase includes a pro forma adjustment that incorporates 12 months of PTYP, from July 1, 2022 through June 30, 2023. This adjustment is structured in the same manner as similar adjustments made in connection with APS's two preceding rate

cases. It includes only plant that is placed in service by the conclusion of the PTYP period, and the calculation will be updated as the case proceeds to reflect actual costs of investments that go into service. APS also rolled forward accumulated depreciation, which further reduced the request, and has removed growth-related plant from its PTYP request consistent with Decision No. 76295 (August 18, 2017). Specifically, the Company's PTYP includes items, such as:

- Customer-based technology innovations, including electric vehicle (EV) charging infrastructure and a microgrid facility to enhance system resiliency and service reliability.
- Distribution system upgrades, including pole repair and replacement, substation improvements, and the deployment of grid technology to improve service quality and reliability.
- Renewable generation capital expenditures, including the AZ Sun Battery Phase I Project, the AZ Sun Battery Phase 2 Project, and the Agave Solar Project.
- Nuclear generation upgrades, including advanced water treatment infrastructure to enable the plant to utilize recycled municipal wastewater, as well as upgraded plant control equipment.
- Other generation expenses necessary to support the Company's entire non-nuclear generation portfolio.
- Information technology and facilities, including upgrades to various systems to maintain operational support and security enhancements for critical infrastructure.

2. Changes to Adjustment Mechanisms

Consistent with the Commission's prior rate case decision, APS held collaborative meetings with interested stakeholders and is proposing to modify its current portfolio of adjustment mechanisms. APS proposes to reduce its current set of seven Commission-

approved rate adjustment mechanisms to four active and one inactive adjustment mechanism. The proposal will increase collections through base rates and revise certain adjustor reset dates. Specifically, APS proposes the following:

- Eliminate the Environmental Improvement Surcharge (EIS) adjustment mechanism. In the future, costs currently eligible for recovery through the EIS will be handled through the traditional rate case process.
- Eliminate the Lost Fixed Cost Recovery (LFCR) adjustment mechanism. The costs eligible for recovery through the LFCR will instead be recovered partially in base rates and between rate cases in a revised Demand Side Management Adjustment Charge (DSMAC). In addition, APS proposes enhancements to the DSMAC performance incentive to better align with peak load reduction goals.
- Enhance the Renewable Energy Adjustment Charge (REAC) to recover the capital carrying costs of new, APS-owned clean energy resources and energy storage facilities consistent with the Company's three-year resource action plan required under the Commission's Integrated Resource Planning rules. With this enhancement, customers will benefit from rate gradualism by spreading the cost of investment over time rather than all at once at the conclusion of a rate case proceeding. Customers will also benefit through cost savings where clean-energy tax benefits are matched with investment cost recovery.
- The filing dates for REAC and DSMAC adjustment mechanisms are currently July 1 and June 1, respectively. APS proposed the dates both move to November 1 of each year. Once approved by the Commission, the annual resets for these adjustors will become effective October 1 of the following year.

APS is not requesting any structural changes to the Power Supply Adjustor (PSA), Transmission Cost Adjustment (TCA) mechanism, or the Tax Expense Adjustment Mechanism (TEAM), which is currently inactive and set at zero.

B. Limited Income Programs

APS and its community partners have a long history of providing bill discounts and assistance to those customers who need them the most, through APS's Energy Support and Crisis Bill Assistance programs. APS proposes to continue this important tradition by maintaining the current Crisis Bill Assistance program funding of $2.5 million and enhancing the Energy Support program.

Consistent with the direction provided by the Commission in its last rate case, APS has worked extensively with stakeholders to develop for the Commission's consideration an enhanced two-tiered Energy Support program. This proposal is intended to address APS's most vulnerable customers' energy burdens and provide more support for those with the greatest financial hardship. Under this two-tiered proposal, customers with verified income levels between 0 to 75% of the federal poverty level (FPL) would receive a discount of 60% off of their monthly bills, capped at a discount of $165 per month. Customers with income levels between 75% to 200% of the FPL would continue to receive the current 25% discount, capped at $95 per month.

Given the proposed program design changes, regulatory support is necessary to address both the on-going growth in enrollment and the potential uncertainty regarding the future costs of this program. As such, APS requests that the Commission authorize the Company to track customer discounts applied, and defer program costs incurred above or below the level authorized at the end of this case for potential recovery or refund in a future rate case.

C. AG-X Program Proposal

In the Company's last rate case, the Commission directed APS to engage with AG-X stakeholders to analyze and identify possible solutions on the following issues: cost

shifts, resource adequacy, scheduling imbalance, transmission capacity resource constraints, another buy-through program for smaller and larger customers, the legality of carve outs for specific customer classes, and ensuring equitable opportunities for participation when the program is fully subscribed. To that end, APS has so far held nine collaborative meetings with AG-X stakeholders to discuss the identified issues. As a result of these discussions, APS is proposing the following modifications to its AG-X program:

- Providing AG-X customers two resource adequacy options and corresponding reserve capacity rates from which to choose, depending on whether they elect to provide their own resource adequacy. This change, if adopted, will facilitate the elimination of the $15 million being recovered in the PSA mechanism and mitigate the cost shift to non-AG-X customers.
- Modifying the program's administrative charge to more accurately reflect the cost to manage the AG-X program.
- Modifying the notification times required to leave the AG-X program to ensure that APS has adequate time to procure replacement resources in a cost-effective manner for customers.
- Expanding program eligibility to allow E-32 Medium and E-32 Small customers to participate and reduce the aggregate peak load requirement from 10MW to 5MW.

APS intends to continue its collaboration and engagement with the AG-X stakeholders on remaining issues after the filing of this Application.

D. Coal Community Transition (CCT)

To address the economic ramifications of the retirement of the Company's coal-fired plants, APS is seeking Commission approval of those portions of the Company's CCT proposal that were not approved in the 2019 Rate Case. APS is requesting to recover $106.5 million over nine years, with approximately $16 million in the first year, through its REAC mechanism. This $106.5 million funding request represents the level of CCT

funding that APS requested in its last rate case (less the CCT funds approved in Decision No. 78317), and would be allocated as follows:

- $3.75 million for the Navajo Nation to support home and business electrification efforts.
- $10.4 million for the Navajo County communities in CCT financial support.
- $2.35 million for the Hopi Tribe in CCT financial support.
- $90 million for the Navajo Nation in CCT financial support.

E. Changes to Service Schedules

APS proposes the following changes to its Service Schedules:

- Revise Service Schedule 1 to simplify and update existing language, including revisions to Section 12 (Limitations on Liability of Company) to make the language consistent with peer electric utilities (as previously approved by the Commission) and to eliminate inapplicable terminology;
- Revise Schedule 3 to simplify the construction process for customers and clarify terms; and
- Revise Schedule 9 to increase the availability of the economic incentive for rural applicants.

F. Residential Rate Design

APS proposes to keep residential rate structure changes to a minimum, continue the Commission-directed efforts to provide customer education focused on rate selection, and work to increase affordability and narrow the range of bill impacts. In addition, APS proposes to eliminate in-network payment fees for all customers, including credit card fees and in-person kiosk fees. APS further proposes to offer two additional off-peak holidays for time-of-use (TOU) rate plans, specifically Juneteenth (which is observed on June 19 of each year) and Indigenous Peoples'/Columbus Day (which is observed on the second Monday in October of each year), both of which are recognized as state and federal holidays.

G. General Service Rate Design

APS proposes the following changes to its general service rate offerings:

- Increase the rates to reflect the requested increase in revenue requirements for the class.
- Revise streetlighting Rate Schedules E-45 and E-68 to conform with current conditions.

II. STATEMENTS IN SUPPORT OF APPLICATION AND RELIEF REQUESTED

In support of this Application, APS states as follows:

1. APS is a corporation duly organized, existing, and in good standing under the laws of the State of Arizona. Its principal place of business is 400 N. 5th Street, Phoenix, Arizona, 85004.
2. APS is a public service corporation, engaged in the generation, transmission, and distribution of electricity for sale in Arizona. In conducting such business, the Company operates an interconnected and integrated electric system.
3. All communications and correspondence concerning this Application, as well as discovery and pleadings with respect thereto, should be served upon:

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And also:

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4. This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of the public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearings, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery, and other prehearing and post-hearing matters.
5. Accompanying this Application are all the relevant SFRs and rate design schedules required by A.A.C. R14-2-103[4] as well as the supporting direct testimony and attachments of the witnesses identified above. In Decision No. 78317, the Commission requested that the Company identify a way to present separate "jurisdictional only" schedules. The Company intends to submit a separate set of jurisdictional schedules for informational purposes within 30 days.
6. The Company respectfully requests that this Commission set a date for the hearing on this Application such that new rates for the Company will become effective by December 1, 2023. At the hearing conducted pursuant to this rate request, APS alleges and will establish, among other items, that:
    a. APS's current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;
    b. The requested increase produces the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, preserve the Company's financial

[4] This Application does not include SFR Schedule E-6 because that schedule applies only to a "combination utility" within the meaning of A.A.C. R14-2-103(A)(3)(q), and APS is not a "combination utility."

integrity and stability, and permit the Company to attract new capital investment on reasonable terms;

c. The Company requires additional permanent revenue of at least $460 million, based on annualized test period sales, calculated as described in this Application, in order to continue to provide, both now and in the future, safe, adequate, and reliable electric service to its customers as required by law;

d. APS's new rates and service offerings for residential and general service customers are in the public interest and should be approved;

e. The Company's proposed modifications to existing rates and service schedules are in the public interest and should be approved;

f. The Company's proposed CCT funding is in the public interest and should be approved;

g. Regarding its limited-income Energy Support program, that the Company be allowed to track discounts applied to customers' bills and defer program costs incurred above or below the levels authorized in this case for future recovery or refund. Accordingly, APS requests that any final order in this case contain the following language as part of its ordering language:

> IT IS FURTHER ORDERED that APS is authorized to track discounts paid to customers and to defer program costs incurred above or below the level authorized in this case on the limited-income programs (E-3 and E-4) for possible later recovery or refund through rates. Nothing in this Decision shall be construed in any way to limit this Commission's authority to review the entirety of the program and to make any disallowances thereof due to imprudence, errors, or inappropriate application of the requirements of this Decision;

h. The Company's proposed modifications and enhancements to current adjustment mechanisms are in the public interest and should be approved;

i. The Company's depreciation rates and its modifications to the Palo Verde Generating Station decommissioning funding contribution allocation (as proposed and discussed in the Direct Testimony of APS witness Elizabeth Blankenship and set forth in Attachment EAB-02DR) are in the public interest and should be approved. In order to effectuate the necessary change in the allocation of decommissioning funding, APS requests that any final order in this case contain the following language as part of its ordering language:

> IT IS FURTHER ORDERED that the decommissioning costs recommended by APS are adopted as set forth in the decommissioning contribution schedule attached as Appendix [X] to this Decision;

and

j. All other proposals supported by the testimony and the accompanying exhibits are in the public interest and should be approved.

7. In addition to setting a hearing date, APS asks that the Commission issue a procedural order setting forth the prescribed notice for the Application, establishing procedures for intervention, and providing for appropriate discovery.

RESPECTFULLY SUBMITTED this 28th day of October 2022.

By: /s/ Melissa M. Krueger
Melissa M. Krueger
Jeffrey S. Allmon
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ORIGINAL electronically filed
this 28th day of October 2022, with:

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/s/ RS

Attachment A

APS Direct Testimony
Executive Summary

Theodore N. Geisler
President
Arizona Public Service Company

Direct Testimony Overview

Mr. Geisler provides a general overview of the Company's rate request. He discusses APS's commitment to serve all customers with safe, reliable, and clean energy, as well as the steps the Company is taking to ensure that the APS energy grid is resilient to meet any challenges it faces. He explains the importance of the Company's financial stability to customers. Finally, he discusses the proposed changes to the Company's adjustment mechanisms.

Direct Testimony Key Points

- APS proudly serves more than 1.3 million homes and businesses in 11 of Arizona's 15 counties spanning roughly 35,000 square miles.

- APS customers are at the center of the work we do, and we have made and are continuing to make investments to serve and support our customers with safe, reliable, and clean energy. On average, the Company invests approximately $1.5 billion annually in building a reliable, more resilient energy grid for our customers. APS customers' average rates have remained flat and below the national average since 2018. Given rapid load growth in our service territory, and based on current and projected economic conditions, APS's rate proposal will allow us to improve our financial stability so we can cost-effectively access the capital needed to meet our customers' needs. Restoring financial stability reduces credit rating risk, improves equity investor confidence in the Company, and ensures that APS can access lower-cost capital, which in turn reduces overall costs for customers.

- APS continues to experience substantial customer growth in our service territory that has required significant additional investment during the Test Year. We expect growth to continue, while at the same time customers will experience increasing needs for energy resiliency and grid reliability. The requested rate relief will enable APS to continue to meet the following commitments to its customers: (1) ensure reliability and resilience of the energy grid; (2) secure a clean, balanced energy supply for Arizona; and (3) improve customer support.

- In order to meet these commitments to customers, APS is requesting an overall net customer rate increase of $460 million which represents a 13.6% increase to base revenues. In this case, the Company is requesting this increase to become effective on December 1, 2023. Our request is based on a Test Year ending June 30, 2022, a return on equity of 10.25%, and results in a 7.17% weighted average cost of capital. APS is also requesting a return on the fair value increment of 1%, resulting in a proposed fair value rate of return of 4.92%. Based on revisions APS is proposing to its current set of seven rate adjustment mechanisms, the day-one net bill impact of the requested rate increase on all customers is an average of 13.6%.

- Included in this case are several modifications to our adjustment mechanisms to simplify them, while maintaining the financial benefits of timely recovery of specified costs that promote rate gradualism and reduce the frequency of rate case filings. This includes the consolidation of seven current adjustors to four active and one inactive adjustor as follows:
    - Eliminate the Environmental Surcharge Adjustor and collect costs through base rates;
    - Eliminate the Lost Fixed Cost Recovery Mechanism and collect costs through base rates and the Demand Side Management Adjustor Mechanism;
    - Enhance the Renewable Energy Adjustor Charge to allow recovery of clean energy generation and storage investments to support balanced, clean investment while also promoting parity between APS-owned resources and purchased power agreements;
    - Maintain the Power Supply Adjustor to ensure timely recovery of fuel and purchased power costs;
    - Maintain as inactive the Tax Expense Adjustor Mechanism; and
    - Maintain the Transmission Cost Adjustor.

APS Direct Testimony
Executive Summary

Jacob Tetlow
Executive Vice President of Non-Nuclear Operations
Arizona Public Service Company

Direct Testimony Overview

Mr. Tetlow provides testimony on the Company's safety and reliability performance, its post-Test Year plant (PTYP) request, and its Coal Community Transition (CCT) proposal. He explains electric vehicle (EV) infrastructure efforts underway in support of the Statewide Transportation Electrification Plan, along with other generation and non-generation infrastructure investments projected to be necessary as APS increases its reliance on clean energy resources.

Direct Testimony Key Points

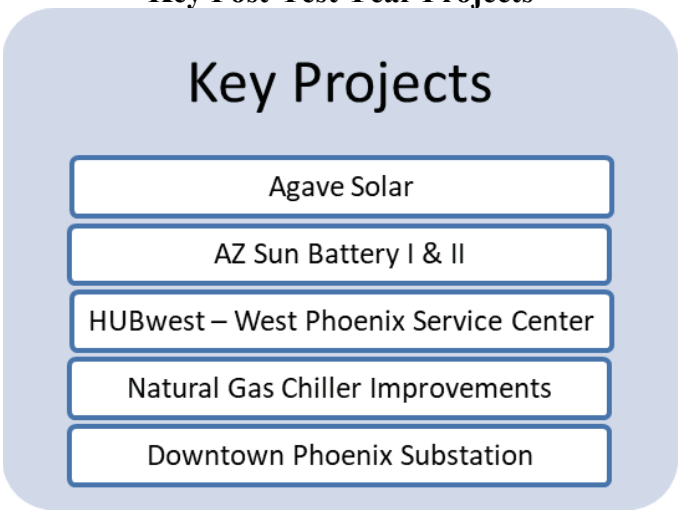
- The first and highest priority for all APS employees is to work safely and ensure the safety of the communities they serve. APS has a rigorous safety program and Safety Management System in place and continually looks to improve the effectiveness of its safety culture and ensure regulatory compliance.

- APS has over 35,000 square miles of service territory with an infrastructure spanning one of the most geographically diverse regions in the country. This area includes a variety of elevations, climates, and jagged terrains that can be challenging to navigate. The expansive territory over which this infrastructure must operate requires continual system maintenance to ensure the reliability customers expect in all weather conditions.

- APS provides industry-leading reliability and consistently delivers at or better than annual Edison Electric Institute (EEI) top-quartile reliability when compared to peer utilities across the country. Specifically, the Company has achieved top quartile System Average Interruption Frequency Index (SAIFI) performance nine out of the last ten years and top quartile System Average Interruption Duration Index (SAIDI) performance for eight out of the last ten years. It was also ranked in the top five among all U.S. utilities for "Perfect Power" at the end of 2021, a measure of the J.D. Power residential survey. This reliability performance is the result of many programs and strategies requiring significant investment to enhance grid resiliency.

- APS is requesting $1.5 billion in total Company gross capital expenditures for the 12-month period ending June 30, 2023, which is the 12-month period immediately after the Test Year in this case. In addition, APS will roll forward accumulated depreciation and taxes during the PTYP period, which further reduces its PTYP request by approximately $689 million. Thus, APS is requesting $788.8 million be added to rate base for PTYP. It is projected that all assets in the Company's PTYP request will be serving customers prior to the anticipated rate effective date in this case. The Figure below highlights a few of the projects included in the PTYP.

Key Post-Test Year Projects



- The investments that make up the Company's PTYP request are focused on the following: (1) securing a clean and balanced energy supply for Arizona through investments in renewable energy and energy storage projects in addition to improvements to APS's existing generation resources; (2) improving the information technology and physical facilities that support efficient and safe work processes, while also making them more sustainable; (3) ensuring that Palo Verde Generating Station—the nation's largest power producer of any kind for more than 25 years, all of it carbon-free—continues to provide safe and reliable service; (4) improving the resiliency, sustainability, and efficiency of APS's electricity delivery systems; and (5) ensuring that APS's non-nuclear generation provides clean, efficient, and top quartile performance that balances and maintains a reliable electricity grid.

APS Direct Testimony
Executive Summary

Monica Whiting
Vice President, Customer Experience and Communications
Arizona Public Service Company

Direct Testimony Overview

Ms. Whiting provides a summary of APS's recent customer service improvements and discusses the Company's proposals to meet its customer's evolving needs and expectations.

Direct Testimony Key Points

- APS's customers have experienced positive improvements as it relates to the customer experience. The Company's most recent J.D. Power results have APS in the second quartile for overall residential customer satisfaction and in the first quartile for overall business customer satisfaction.

J.D. Power Quartile Improvements to Attributes and Key Indicators Shaped by Communications

J.D. Power Customer Satisfaction Attributes and Key Indicators Shaped by Communications	2021 Quartile	Q3 2022 Quartile	Trend
Efforts to Communicate Changes that Affect Account/Service	4	2	↑
Creating Messages that Get Your Attention	4	3	↑
Recall of Utility Communications	3	2	↑
Ease of Understanding Your Pricing Options	4	2	↑
Efforts to Help You Manage Your Monthly Usage	4	2	↑
Customer Awareness of Energy Efficiency/Conservation Programs	2	1	↑

- APS is proposing to enhance the Company's Energy Support Program by establishing a tiered approach to limited-income customer support based on energy burden. The proposed structure has two tiers based on income level. Customers earning between 0-75% of the Federal Poverty Level (FPL) would receive a 60% discount off of their monthly bill, capped at $165 per month. Customers earning between 75%-200% of the FPL would receive a 25% discount, capped at $95 per month. Customers with qualifying medical equipment who earn between 75%-200% of the FPL would continue to receive the 35% discount they receive today. This proposal significantly enhances APS's already high levels of discounts for limited-income customers within the Company's service territory.

- Today, payment fees charged by vendors are passed onto customers directly when they make their payments. In this case, APS proposes to eliminate these payment fees for APS network payment types, and recover the vendor charges for individual transactions in base rates.

- To align with the federal holidays, APS also proposes to add two additional off-peak holidays for customers on time-of-use rates: Juneteenth and Indigenous Peoples' Day/Columbus Day.

APS Direct Testimony
Executive Summary

Andrew Cooper
Senior Vice President and Chief Financial Officer
Arizona Public Service Company

Direct Testimony Overview

Mr. Cooper explains how customers of regulated utilities benefit from a financially stable utility and describes the Company's current financial condition and its importance to Arizona. He provides testimony on the Company's fair value increment proposal, discusses some financial implications of APS's planned retirements of coal-fired resources, and shares information on a clean energy proxy group for the Company and its relationship to APS's proposed return on equity (ROE).

Direct Testimony Key Points

- Cost-effectively meeting the needs of APS's customers requires a balance between ensuring APS's access to capital on reasonable terms and maintaining a stable Arizona regulatory environment. Credit ratings and investor confidence in a financially stable utility company have a direct impact on how much customers pay for electricity. Additionally, establishing the opportunity to earn a fair and reasonable ROE and reducing regulatory lag on infrastructure investments benefits customers by supporting the development of clean, balanced, and resilient infrastructure.

- APS must seek rate relief to sustain the level of investment required to meet the growing needs of its customers. If current trends continue, APS will not have access to cost-effective capital—either debt or equity—to finance the investments necessary to keep up with growing demand within the Company's service territory. This has a direct impact on customers by leading to increases in costs. For instance, the Company has experienced recent credit rating downgrades that have placed upward pressure on APS's cost of short-term debt and its embedded cost of long-term debt, as new long-term debt securities will need to be issued at higher interest rates, which in turn will result in higher cost of debt going forward. That higher cost of debt increases the cost of capital necessary to finance APS's delivery of safe, reliable, and clean electricity and gets passed on to customers through electricity rates.

- The overwhelming trend for the 79 Investor-Owned Utilities in APS's Clean Energy Proxy Group is to retire legacy coal generation and replace that generation capacity with clean resources. Advanced-technology, clean-resource investments are not only a high-value and cost-effective means to provide service to customers, but they also leverage both capital-market preferences for more sustainable investing and recently expanded federal tax credits under the 2022 Inflation Reduction Act.

- Regulatory adjustment mechanisms provide benefits to both customers and the Company. Customers benefit from reduced frequency of rate cases, rate gradualism, the matching of costs and benefits, the ability to pass savings or benefits to customers faster, and the promotion of public policy goals that support customer programs such as energy efficiency, demand response, and access to renewable energy, among others. Investors, lenders, and credit rating agencies favorably recognize the benefits of regulatory adjustment mechanisms and their contribution to predictable and timely cash flows. These entities acknowledge the importance of adjustment mechanisms in reducing regulatory lag and supporting credit quality, which in turn reduces regulatory risk and APS's cost to access capital, which are reflected as customer cost savings.

- APS proposes a 1% return on the fair value increment, which is the difference between the original cost rate base and the fair value rate base.

APS Direct Testimony
Executive Summary

Justin M. Joiner
Vice President, Resource Management
Arizona Public Service Company

Direct Testimony Overview

Mr. Joiner provides an overview of the Company's resource planning and procurement processes, APS's near-term resource needs, and the importance of a diverse energy mix that includes clean energy resources. He describes how APS manages fuel and purchased power expenses and provides a near-term outlook on costs. Finally, Mr. Joiner outlines some of the Company's proposed changes to its AG-X program.

Direct Testimony Key Points

- Across western electricity markets, utility companies are facing serious resource deficiencies. For APS, these challenges are coupled with rapidly growing customer load and extreme weather events that in recent summers have strained electric grids across the Western United States. While neighboring regions have experienced generation reserve and capacity events, APS has been able to ensure that energy is available when customers need it, due to thoughtful resource planning and high performance from its generation resources.

- APS determines resource needs by developing an Integrated Resource Plan (IRP) based on forecasted loads and the resources projected to be necessary to service that load. APS's forecasts project that the Company's load will grow by 1,400 MW by 2026. APS plans to issue All-Source Requests for Proposals (RFPs) to meet the Company's future resource needs over that near-term period, which are being driven by the Company's growing customer demand, the retirement of the Cholla Power Plant, and the expiration of several third-party power purchase agreements (PPAs). APS expects this need to be met by a mix of APS-owned resources and PPAs and makes this determination on a case-by-case basis by evaluating multiple factors.

- A diverse energy mix helps ensure affordability through a balanced portfolio that hedges against commodity and price volatility of generation resources, and enhances resilience with respect to supply chain disruptions, weather patterns, and market conditions.

- Clean energy and storage resources are critical components of APS's diverse energy mix as they provide numerous customer benefits. These include resource cost competitiveness, enhancements to APS's resource diversity, protections for APS's customers from fuel price volatility, the ability to leverage tax incentives to reduce customer costs, and support access to and preservation of APS's access to low-cost capital. In addition, because of substantial customer demand for these resources and APS's high solar resource potential, these investments help create tremendous economic growth opportunities within APS's service territory.

- Natural gas-fired resources remain an important part of APS's energy mix as the Company works to incorporate more renewable resources into its portfolio, especially over the near-term as energy storage technology matures to increase storage durations and supply chains stabilize. Fast-ramping natural gas facilities enable the Company to meet the changing load needs throughout the day and when solar and wind energy resources fluctuate in output.

- The overall cost of fuel and purchased power has increased dramatically over the last two years since the Company's current base cost of fuel was calculated. Over that period, APS has continued its aggressive strategies to mitigate and hedge against the impacts on customers from purchased fuel and power. As of August 31, 2022, the Company's hedging program is expected to save customers $338 million related to natural gas prices in 2022 and approximately $221 million in 2023.

- APS is proposing changes to its large commercial customer electricity buy-through program, AG-X. To ensure resource adequacy, the Company proposes to provide AG-X customers the option to choose from two reserve capacity rates depending on whether they will rely on APS for resource adequacy or provide their own. The proposal also requires AG-X customers who supply their own resource adequacy to provide three years notice to leave the program versus the one year required by AG-X customers who rely upon APS to ensure resource adequacy for their buy-through transactions.

APS Direct Testimony
Executive Summary

Jessica E. Hobbick
Director of Regulation and Pricing
Arizona Public Service Company

Direct Testimony Overview

Ms. Hobbick's testimony provides an overview of the Company's proposed revenue increase and discusses the impact of the increase by customer class. She also explains the Company's proposed changes to its adjustment mechanisms, service schedules, and the AG-X program.

Direct Testimony Key Points

- A summary of the Company's proposed increase, inclusive of adjustor transfers, is summarized in the table below[1].

Net Impact = Net Base Rate Increase + Net Adjustor Changes	**Dollars**	**Bill Impact**
Base Rate Increase		
Total Revenue Deficiency	$772.27M	22.87%
Adjustor Transfers	($107.83M)	(3.19%)
Base Rate Increase Net of Adjustors	$664.44M	19.68%
Day-One Power Supply Adjustment (PSA) Revenue Reduction	($220.59M)	(6.53%)
Day-One Renewable Energy Adjustment Charge (REAC) CCT Revenue Increase	$16.09M	0.48%
Day-One Net Rate Impact	**$459.94M**	**13.62%**

[1] Numbers in this figure have been rounded for ease of presentation.

- APS proposes the following changes to its existing adjustors:

    - Eliminate the Lost Fixed Cost Recovery (LFCR) adjustor, by transferring $58.5 million of Test Year lost fixed cost revenues into base rates and recovering future lost fixed cost revenues in the Demand Side Management Adjustment Charge (DSMAC).
    - Eliminate the Environmental Improvement Surcharge and transfer $10.3 million into base rates.
    - Transfer the Test Year amount of $39.4 million collected in the DSMAC into base rates, which currently recovers $20 million of approved Demand Side Management (DSM) expenses and refine the existing performance incentive to include demand response program net benefits. Based on these changes, the total base rate collections for DSM would be $59.4 million going forward.
    - Revise the Renewable Energy Adjustor Charge (REAC):
        (i) to clarify the Plan of Administration (POA) to allow recovery of carrying costs associated with renewable energy generation and energy storage investments; and
        (ii) to recover Coal Community Transition (CCT) obligations.
    - Retain the Power Supply Adjustor (PSA) and reset the base fuel and chemical rate with a corresponding reduction to the adjustor.
    - Retain the Transmission Cost Adjustment (TCA) mechanism.
    - Leave the Tax Expense Adjustor Mechanism (TEAM) inactive and set at zero.

- APS is proposing to allocate the rate increase in similar proportions across customer classes. The impacts to each customer class are shown in the figure below.

Class	Requested Increase to Retail Revenue	Transfer from Adjustor Rates to Base Rates	Requested Increase to Base Rates	Day 1 PSA/REAC Changes	Day 1 Impact
Residential	22.79%	-3.7%	19.1%	-5.5%	13.6%
General Service					
Extra-Small, Small	23.75%	-3.0%	20.8%	-4.9%	15.9%
Medium	23.58%	-3.2%	20.4%	-7.0%	13.4%
Large	22.30%	-1.7%	20.6%	-7.6%	13.0%
Extra-Large	20.88%	-1.6%	19.3%	-10.1%	9.2%
Schools	24.17%	-5.2%	18.9%	-5.7%	13.3%
House of Worship	23.75%	-5.3%	18.5%	-4.8%	13.7%
Irrigation/Municipal	27.59%	-6.0%	21.6%	-7.9%	13.6%
Outdoor-Lighting	17.67%	-0.8%	16.9%	-3.3%	13.6%
Total Retail	**22.87%**		19.7%		13.6%

- Ms. Hobbick discusses the impacts of the Company's Energy Support Program, the two new off-peak holidays for time-of-use (TOU) customers, and payment fee removal proposals.

- Ms. Hobbick discusses APS's proposed modification to its AG-X program, including modifying the administrative charge, creating options for reserve capacity charges based on the customer's choice of resource adequacy, and expanding the eligibility guidelines to allow E-32 medium and small classes to participate.

- APS proposes to modify its service schedules as follows:

    - **Service Schedule 1** — Simplify and update existing language, including revisions to Section 12 (Limitations on Liability of Company) to make the language consistent with previously approved tariffs of peer electric and to eliminate inapplicable terminology.

    - **Service Schedule 3** — Simplify the construction process for customers by modifying the Statement of Charges methodology to a price per linear foot calculation and also reflect actual equipment costs at the end of the Test Year.

    - **Service Schedule 9** — Increase the availability of the economic incentive for rural applications by 25 MW and use job growth and capital investment criteria to determine the incentive eligibility in Section 4.3 (Effects on Competitors) in place of North American Industry Classification System (NAICS) codes (eliminating these references).

APS Direct Testimony
Executive Summary

Jamie R. Moe
Manager of Regulatory Affairs
Arizona Public Service Company

Direct Testimony Overview

Mr. Moe's testimony outlines APS's Cost of Service Study (COSS) used to support rate design in the Company's Application, as well as the jurisdictional allocation of costs. He also explains the Company's base fuel and purchased power pro formas and the fair value rate base calculation. In addition, Mr. Moe's testimony includes the results of APS's COSS using three methods to calculate costs to serve customers.

Direct Testimony Key Points

- The Company proposes to adjust the current base fuel and purchased power rate of 3.1451 ¢/kWh to 3.8321 ¢/kWh, an increase of 0.6870 ¢/kWh, with an equal and concurrent offset in the fuel costs recovered through the Power Supply Adjustor (PSA at the time rates determined in this proceeding go into effect.

- Mr. Moe sponsors the Company's embedded COSS. As directed by the Commission in its last rate case, APS utilized the Average and Peak (A&P) methodology to allocate production demand costs. The Company maintains that the A&P method does not adequately consider peak demand, which is the key driver for these costs, and requests that the Commission re-examine its preferred method to allocate production demand costs and adopt the Average & Excess (A&E) or 4-CP methods rather than the A&P method.

- APS also performed three separate COSS evaluations for residential solar classes as directed in Decision No. 78317: one using site load, another using delivered load, and a third combining solar customers with non-solar customers within their general rate class.

- Using the Commission-approved methodology of averaging the Original Cost Rate Base (OCRB) and the Reconstruction Cost New Less Depreciation (RCND), the calculated Fair Value Rate Base (FVRB) for APS is $16.6 billion and the current fair value rate of return is 1.43%. The fair value increment is $82.8 million.

APS Direct Testimony
Executive Summary

Elizabeth A. Blankenship
Vice President, Controller and Chief Accounting Officer
Arizona Public Service Company

Direct Testimony Overview

Ms. Blankenship provides the Company's historical and forecasted accounting information and pro forma adjustments required by the Arizona Corporation Commission's Standard Filing Requirements (SFRs) in support of this rate case filing. She sponsors historical financial information for the 12-month period that ended June 30, 2022, which was used as the Test Year in this proceeding, as well as financial information for any prior years or projected information presented on certain SFR Schedules.

She explains the capital structure of the Company and provides APS's actual overall cost of capital.

Direct Testimony Key Points

- APS's filing includes historical accounting data, including the actual data for the Test Year. The majority of this information is disclosed directly or indirectly in both the consolidated APS and consolidated Pinnacle West Capital Corporation audited and reviewed financial statements. This same information is included in filings made with the Federal Energy Regulatory Commission and Securities and Exchange Commission for the relevant years.

- The Total Company adjusted Original Cost Rate Base (OCRB) of $13.2 billion is included as well in APS's filing. The amount of the adjusted OCRB allocated to the Commission jurisdiction is $10.5 billion. APS is proposing a return on common equity of 10.25%, which is supported by testimony from APS witness Dr. Morin.

- Ms. Blankenship sponsors various rate base and income statement pro forma adjustments. These are consistent with prior filings and include normalizations, annualization, and out-of-period adjustments. All of the pro forma adjustments discussed in Ms. Blankenship's testimony reflect Total Company amounts prior to any jurisdictional allocation.

- Finally, APS's filing proposes a change to the allocation of the annual decommissioning funding between the three units at Palo Verde Generating Station.

APS Direct Testimony
Executive Summary

Dr. Roger A. Morin
Principal, Utility Research International

Direct Testimony Overview

Dr. Morin provides recommendations for APS's return on equity (ROE). Dr. Morin concludes that a minimum ROE of 10.25% is required for APS to attract capital on reasonable terms, maintain its financial integrity, and maintain an opportunity to earn a return commensurate with comparable risk investments.

Direct Testimony Key Points

- The standard for establishing a fair ROE requires that a regulated utility be allowed to earn a return equivalent to what an investor could expect to earn on an alternative investment of equivalent risk. Dr. Morin's approach to estimating the cost of equity for APS focuses on measuring the expected returns required from investments into companies that face business and financial risks comparable to those faced by APS. In accordance with recent trends across the market, risk perceptions of the electric utility industry have intensified dramatically, which is why cost of equity estimates for businesses operating in this sector are escalating.

- In developing his ROE recommendation, Dr. Morin applied a number of rigorous and generally-accepted cost of capital estimate methodologies, including the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), and a Risk Premium Model. Multiple methods are used, because no one single method provides the necessary level of precision for determining a fair return. Nonetheless, each method provides useful evidence to facilitate an informed judgment based on sound, generally-accepted methods across the industry.

- Dr. Morin concludes that a minimum ROE of 10.25% is required for APS to attract capital on reasonable terms, maintain its financial integrity, and maintain an opportunity to earn a return commensurate with comparable risk investments. This ROE is conservative, given the higher relative risks APS confronts by virtue of its significant external financing requirements from its large construction program, a rising interest rate environment, generally heightened industry risk across North American electric utilities, and operating within what is generally considered to be a high-risk regulatory environment.

- Dr. Morin explains that authorizing an ROE below the level required for investment into a comparably-risky enterprise can negatively impact customers. A low ROE ultimately leads to the utility having to rely on more debt financing, which results in investor uncertainty about future dividends and earnings. This in turn results in APS equity becoming a riskier investment. The risk of default on a company's bonds also increases, making the utility's debt a riskier investment. Collectively, the conditions resulting from an ROE set lower than comparable-risk enterprises increase the cost to the utility for both debt and equity financing. Ultimately, the increased cost to access capital increases costs for customers, while also increasing the risk that APS would not be able to access the capital needs for financing customer infrastructure needs.

DIRECT TESTIMONY OF THEODORE N. GEISLER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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ATTACHMENT LIST

Excerpt from S&P Global, *Adjustment Clauses: A State by State Overview,* Regulatory Focus Topical Special Report (July 18, 2022) ..... Attachment TNG-01DR

DIRECT TESTIMONY OF THEODORE N. GEISLER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Theodore N. Geisler. I am the President of Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West Capital Corporation (Pinnacle West). As President, I have oversight and responsibility for the Company's core utility functions, including transmission and distribution, non-nuclear generation, resource management, customer experience, regulatory, information technology and supply chain. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree from Colorado State University and a Master of Business Administration from Arizona State University. I joined APS in 2001 in the generation area and have served in a variety of roles throughout the Company since then, including leadership roles in resource operations, transmission and distribution operations, investor relations, corporate strategy, information technology, and most recently as Chief Financial Officer.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide a general overview of APS's request in this proceeding. I discuss APS's commitment to serve all customers with safe and reliable energy, as well as the steps the Company is taking to ensure that the APS energy grid is resilient to meet any challenges that we may face. I explain the importance of the Company's financial stability to customers. I also provide insight into the proposed changes to our adjustment mechanisms.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. APS has a strong track record of providing safe and reliable electric service. I reaffirm our commitment to ensure reliability and resilience of the energy grid, secure a clean, balanced energy supply of electricity, and continuously improve our customers' experience with us.

APS does not file this rate request lightly and we recognize the Commission's role in balancing what is in the best interest of the public today and over the long term. This rate case is necessary to ensure that APS has the financial stability to reliably serve our customers – today and in the future. APS continues to experience substantial customer growth in our service territory that has required significant additional investment during the Test Year. We expect growth to continue, in addition to growing needs for energy resiliency and grid security.

To compete for and obtain low-cost financing in the market, which is necessary to fund the infrastructure investments customers need, APS must demonstrate that (i) it is a financially stable utility; (ii) it has reasonable opportunity to recover its costs in a timely manner; and (iii) it has the ability to provide a competitive, market-aligned return on equity for investors. Restoring financial stability reduces credit rating risk and ensures lower cost of financing to keep rates low for customers. Our rate case proposal seeks relief that will allow us to establish financial stability so we can borrow the capital needed to meet our customers' needs. Included in this rate case are several modifications to our adjustment mechanisms to simplify them, while maintaining the financial benefits of timely recovery of specified costs that promote rate gradualism and minimize rate case filings. APS must regularly add new generation resources in coming years to keep up with customer growth while ensuring grid reliability and resiliency. APS expects substantial growth in clean

resources to create a balanced resource mix while delivering the benefits of clean resources to customers. This rate case realigns our adjustment mechanism to ensure steady and competitive procurement of new clean resources to keep up with growth and grid resiliency while minimizing customer impact.

II. MEETING THE NEEDS OF APS CUSTOMERS

Q. PLEASE PROVIDE AN OVERVIEW OF APS.

A. Since 1886, APS and its predecessors have been a vital part of Arizona's communities, growth, and innovation. Arizonans have relied on us to deliver critical public service that has become an increasingly important part of their lives. Today, we proudly serve more than 1.3 million homes and businesses in 11 of Arizona's 15 counties.

APS serves nearly 35,000 square miles of territory and is one of the most geographically diverse regions which includes a variety of elevations, climates, and terrains. We maintain more than 33,000 miles of transmission and distribution lines; we are a co-owner and the operator of Palo Verde, the largest nuclear generation facility in the country; and we contribute an estimated $3.4 billion annually in economic impact to the state.

More than a company, APS is the nearly 6,000 women and men who work outside on the grid, in warehouses, at power plants, in control rooms, and all throughout the state to meet the needs of our customers 24 hours a day, 365 days a year. When storms roll in, APS employees are there to protect the grid and restore service when needed. In blistering 115-degree temperatures, APS employees have materials staged and crews standing by to rapidly respond.

APS is also the Customer Experience Center employees answering customer calls through the night, the cybersecurity control room operators protecting against threats, and many other employees working around the clock to ensure reliable service for our customers.

It is because of this team that APS is ranked in the top quartile nationally for electric service reliability. In fact, Arizona's energy grid was recently recognized as one of the most reliable in the country according to *U.S. News & World Report*. More specifically, APS frequently ranks in the top quartile of Edison Electric Institute (EEI) reliability metrics, compared to peer utilities in the industry.

Maintaining superior reliability also requires diligent planning and securing adequate resources to meet the growing needs of Arizona, upgrading and maintaining existing equipment to anticipate and avoid problems before they happen, and investing in new infrastructure. Importantly, this planning and infrastructure investment must occur before our customers need it on those blistering summer days. On average, we continue to invest roughly $1.5 billion annually in building a reliable, more resilient energy grid.

Q. HOW IS APS'S RATE CASE FILING DESIGNED TO MEET CUSTOMER NEEDS?

A. APS customers are at the center of the work we do and we have made, and are continuing to make, investments to serve and support our customers with safe, reliable, and clean energy. APS needs the requested rate relief to enable it to continue to meet the following commitments to its customers:

- Ensure reliability and resilience of the energy grid;
- Secure a clean, balanced energy supply for Arizona; and
- Improve customer support.

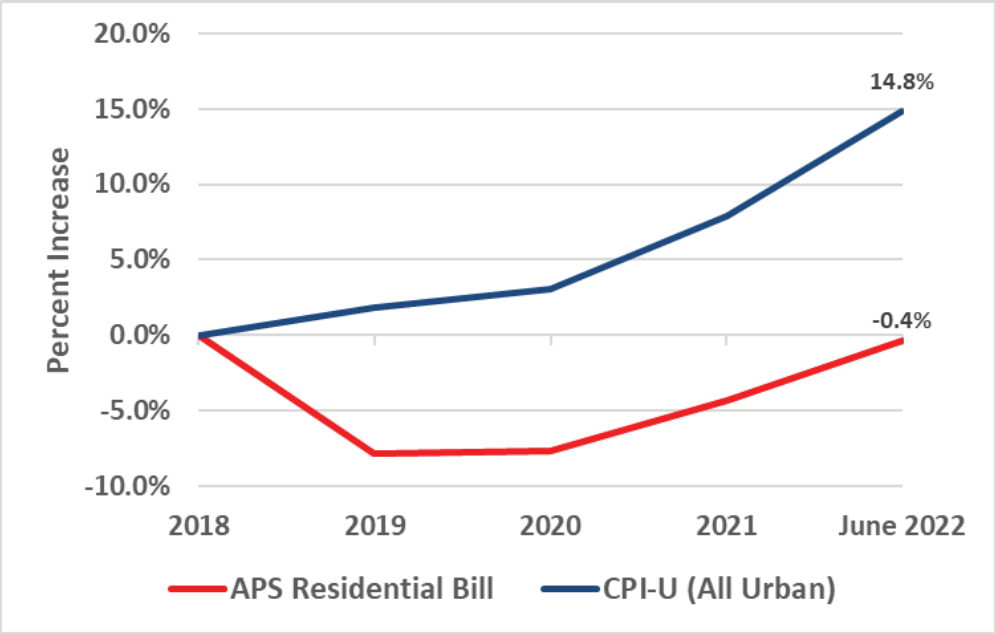
All three commitments are critical to meeting the needs and expectations of customers now and in the future – a responsibility APS takes very seriously.

The fact is, however, that since our last rate case filing in October 2019, which had a test year ending in June 2019, we have made significant investments in the energy grid to maintain a strong, reliable, and resilient energy infrastructure and to keep up with the substantial growth our state is experiencing. The challenges of maintaining reliability and resiliency continue to increase and it is also critical now to make investments that will secure an adequate and predictable energy supply for the future. Arizonans expect us to be responsible stewards of the grid and the requested rate increase is necessary to fulfill our responsibilities and commitments.

Q. WHAT STEPS HAS APS TAKEN TO REDUCE COSTS AND KEEP RATES AFFORDABLE FOR CUSTOMERS?

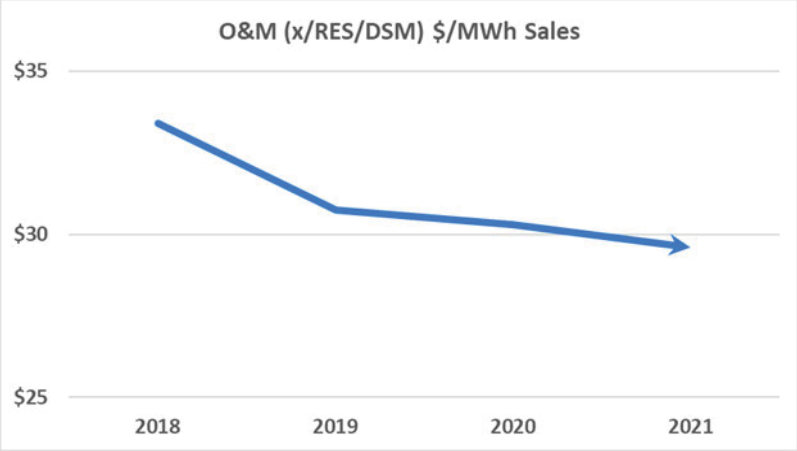
A. APS electricity rates are flat compared to 2018 levels and, for the past six years, have remained below the national average, while energy rates across the country rose, on average, 8.1% from December 2018 through December 2021, according to the Energy Information Administration. During this period, APS has engaged in careful capital management and planning, taken proactive steps to ensure that tax reform savings are passed on to customers, managed purchased fuel and power to ensure that savings are passed on to customers through adjustment mechanisms, and carefully balanced its assets, liabilities, and equity. Furthermore, APS rates remain well below the Consumer Price Index – All Urban (CPI-U) category. The CPI-U is a relative measure of consumer inflation and represents the average price paid over time for consumer goods. The CPI-U rose by 14.8% since 2018, while the average APS residential bill was 0.4% lower at the end of the Test Year than in 2018, as evidenced in Figure 1 below.

Figure 1. Percent Increase in an Average APS Residential Bill vs. Consumer Price Index-All Urban (CPI-U) through the End of the Test Year



Cost control is crucial to keeping rates affordable and enhancing APS's ability to invest the capital necessary to serve customers. APS has consistently focused on cost management, with an overall declining operations and maintenance (O&M) cost per MWh sales over the last several years, as shown in Figure 2. This helps to offset a portion of the required capital investment-related costs.

Figure 2. Operations and Maintenance Costs per MWh Sales



Relative to broader economic conditions, APS's aggressive cost-control measures can only go so far in keeping electricity rates low for customers, especially given recent inflationary trends (i.e., the CPI-U inflation rate was 9.1% as of Test Year end compared to just 0.6% two years earlier in June 2020[1]). APS expects these high prices to continue into 2023 due to long lead times, inventory turnover, and an unstable geopolitical environment. With the substantial investments APS is making to improve the customer experience, ensure reliable service from a resilient grid, and develop a more balanced and cleaner portfolio of resources, APS's rate request is necessary to meet the needs of its growing customer base.

Q. PLEASE EXPLAIN WHY APS'S FINANCIAL STABILITY IS IN THE BEST INTERESTS OF THE COMPANY'S CUSTOMERS AND ALL OF ARIZONA.

A. To fund operations and build infrastructure to serve customers and further support Arizona's energy security, APS must raise hundreds of millions of dollars of financing each year. Because the costs of financing these investments can be

[1] United States Bureau of Labor Statistics, Database for Consumer Price Index for all Urban Consumers, accessed September 27, 2022 at https://data.bls.gov/cgi-bin/surveymost.

substantial, customers benefit when APS has access to low-cost capital on reasonable terms, both in the form of debt and equity.

As APS witness Andrew Cooper explains in his direct testimony, to compete for and obtain low-cost financing in the market, APS must demonstrate not only that it is a financially stable utility, but that it has reasonable opportunity to recover its costs from customers in a timely manner and that it can provide a competitive, market-aligned return on equity. In addition, lenders evaluate credit metrics to determine if they want to lend financing and at what cost. Companies with higher risks of recovery, longer lag time in recovery or deteriorating credit metrics, will have increased capital costs because there are fewer lenders willing to offer capital under these circumstances. This reduced group of lenders results in less competition for capital, which ultimately increases the financing costs for customers. Thus, maintaining a healthy credit rating and financial outlook is critically important to APS's ability to keep costs affordable for customers. All of this translates into lower electricity rates for customers and higher quality of service. For these reasons, there is a direct relationship between APS's financial health and its customers' experience.

III. APS'S RATE CASE REQUEST

Q. DID APS WORK WITH STAKEHOLDERS PRIOR TO FILING THIS APPLICATION?

A. Yes. APS collaborated with a broad coalition of stakeholders to discuss potential solutions and gather feedback on a variety of customer-oriented issues. In 2022, the Company held 23 rate case-specific group stakeholder collaboration meetings involving more than 40 organizations. Specifically, APS collaborated with stakeholders on the following items: proposed enhancements to its limited income support program; modifications to its large customer generation buy-through

program, AG-X; modifications to adjustment mechanisms; and other proposals as required by Decision No. 78317 (November 9, 2021). Our collaboration efforts have resulted in a proposed modification to Service Schedule 4 that provides schools with money-saving metering options, a revised scheduling protocol for AG-X customers that is expected to reduce the cost of imbalance settlements, and the filing of two Commission-requested electric vehicle (EV) rates for customers.

In addition to stakeholder collaboration focused on items specific to this rate case, various APS teams continue to meet regularly with stakeholders to discuss topics of interest to APS customers and Arizona's energy future. For example, APS engages monthly with the Resource Planning Advisory Council, Consumer Work Group and Customer Advisory Board, to solicit feedback and continue improving the customer experience. APS is strongly committed to continuing stakeholder discussions on items included in the rate case and other ongoing efforts as we recognize this collaboration is key in developing outcomes that meet the needs and expectations of our customers.

Q. PLEASE PROVIDE AN OVERVIEW OF APS'S REQUEST IN THIS PROCEEDING.

A. APS is requesting an overall net customer rate increase of $460 million which represents a 13.6% increase to base revenues, and the Company is requesting rates reflecting an increase in that amount to become effective on December 1, 2023. This request is based on a Test Year ending June 30, 2022, an ROE of 10.25%, and results in a 7.17% weighted average cost of capital. APS is also requesting a return on the fair value increment of 1.0%, resulting in a proposed fair value rate of return of 4.92%.

APS is also proposing the inclusion of 12 months of post-Test Year plant (PTYP) in its request. Projects that have or are expected to enter service and become used and useful during the period July 1, 2022 through June 30, 2023 have been included in the request. APS witness Jacob Tetlow will discuss these investments in more detail in his testimony. In alignment with recent Company PTYP requests and Commission decisions, APS has removed growth-related plant from its PTYP request and has rolled forward accumulated depreciation and taxes, which significantly reduces the Company's PTYP request.

In this case, APS also proposes a comprehensive, customer-focused revision to the Company's current set of seven rate adjustment mechanisms, which I discuss in further detail later in my testimony.

The day-one net bill impact of the requested rate increase on all customers is an average of 13.6%. Both residential and general service class will see an average bill impact of 13.6%.

Figure 3. Overview of APS's Request[2]

Overview of Rate Increase	Dollars	Bill Impact
Base Rate Increase		
Total Revenue Deficiency	$772M	22.9%
Test Year Adjustor Revenue Transfers	($108M)	(3.2%)
Base Rate Increase Net of Adjustors	$664M	19.7%
Net Rate Increase		
Day-One Power Supply Adjustment (PSA) and Renewable Energy Adjustment Charge (REAC) Changes	($204M)	(6.1%)
Day-One Net Rate Impact	**$460M**	**13.6%**

Q. PLEASE EXPLAIN OTHER SIGNIFICANT ASPECTS OF APS'S REQUEST.

A. APS is proposing to update the base fuel and purchased power rate from 3.1451 ¢/kWh (authorized by the Commission in Decision No. 78317) to 3.8321 ¢/kWh. As shown in Figure 3 above, this proposal includes an equal and concurrent offset in costs recovered through the Power Supply Adjustment (PSA) at the time rates determined in this proceeding become effective. APS witness Justin Joiner will discuss recent impacts of price and other factors to the Company's fuel and purchased power expense requiring this base fuel increase in more detail in his testimony, and APS witness Jessica Hobbick will discuss the impact of the PSA offset in her testimony.

APS is proposing to continue our focus on Commission directed efforts to provide customer education focused on rate selection and is therefore recommending

[2] Numbers in the figure have been rounded for ease of presentation.

minimal changes to rate design. As further described by APS witness Monica Whiting and Ms. Hobbick, APS is proposing to remove payment fees for all customers in addition to providing our limited income customers with an enhanced, energy burden-based Energy Support Program.

To build upon the success of the Company's Commission-approved economic development program (Service Schedule 9), which is currently fully subscribed, APS is also proposing an increase in program size to allocate exclusively to rural-based businesses as discussed in Ms. Hobbick's testimony.

Additionally, APS is proposing modifications to its AG-X program to include additional resource adequacy requirements to ensure the program can continue reliable operations and allow broader customer participation. These changes are further described by Mr. Joiner and Ms. Hobbick.

IV. COMMITMENT TO CUSTOMER EXPERIENCE

Q. PLEASE SUMMARIZE APS'S VISION AND IMPROVEMENTS TO THE CUSTOMER EXPERIENCE.

A. APS is most successful when customers are satisfied with the reliable service and customer experience they receive. In her direct testimony, Ms. Whiting details customer experience improvements we have made along with our plans to continue improving. This includes enhancing our current limited income discount program, removing payment transaction fees for all customers, adding additional off-peak holidays for customers on time-of-use plans, and providing customers with greater access to information and support. These proposals aim to achieve one of our most important goals: acting on feedback from customers, stakeholders, and the Commission to improve the customer experience over the next several years.

Importantly, APS is committed to listening to its customers. We have established a customer advisory board and a customer stakeholder group. We regularly survey customers and have established customer experience driver teams within our Company to focus on implementing feedback from customers across all areas of our business.

To that end, APS is also committed to ensuring a culture exists in which every APS employee is empowered to do the right thing for our customers. All of APS's nearly 6,000 employees are encouraged to advocate for our customers. And, our leadership team is committed to continuous collaboration with stakeholders.

Q. WHAT IMPROVEMENTS HAVE YOU MADE IN MEETING THE NEEDS OF CUSTOMERS SINCE THE LAST RATE CASE?

A. Based on APS's proposals adopted by the Commission in the last rate case, the Company rolled out a series of customer-oriented initiatives this past December. For example, customers now have the option of three simplified rate plans, an extended time to pay their bill each month, the addition of two off-peak holidays, and more funding for low-income customers who need assistance to pay their bills. APS also made enhancements to the APS website, our interactive outage map, and our alerts by text and email to improve customers' digital experience and increase engagement.

In addition, we have improved our process for estimating restoration times during outages for customers and have improved our call center service levels for calls being answered in 30 seconds or less. The Company has also enhanced communications to help customers understand their pricing options.

These efforts are paying off as reflected by our improving J.D. Power residential and business customer satisfaction survey scores. APS made quartile gains in every single driver of residential customer satisfaction through the first three quarters of 2022, propelling the Company to the second quartile for overall residential customer satisfaction when compared to its large investor-owned peers. APS's strongest performing driver in the latest J.D. Power survey was Customer Care, phone and digital, which leaped to the first quartile and performed well above the large investor-owned peer set averages. Additionally, through the first two quarters of the year, J.D. Power overall satisfaction for business customers has risen to first quartile. Ms. Whiting further discusses our improvements for customers in her testimony.

V. ENSURING POWER RELIABILITY AND GRID RESILIENCY

Q. HOW DOES APS ENSURE RELIABLE AND AFFORDABLE POWER AND A RESILIENT ENERGY GRID FOR CUSTOMERS?

A. Customers count on APS to power their lives and businesses. Our commitment is to continue to deliver the reliable service Arizonans have come to expect while continuously improving grid resiliency and security. This rate request supports investments in our energy infrastructure to ensure that all customers, wherever they live in our service territory, continue to receive reliable electric service under all weather conditions. As maintenance expenses rise and the grid continues to expand, we are committed to balancing the need for affordability with the critical importance of investing for the reliability and resilience customers expect.

As I have previously mentioned, APS is one of the most reliable electric providers in the country based on national indices comparing utilities across the country. We have maintained stable EEI top-quartile reliability as a result of the infrequency in which our customers experience an outage nine out of the past ten years, and eight

out of the past ten years for the average outage duration customers experience, which is exceptional in our industry. This is the result of constant vigilance and prudent planning. Maintaining a reliable and resilient energy grid requires constant vigilance and investment to anticipate and respond to changing weather, usage habits, and economic development in the region .

Our ability to deliver reliable service, at this time, when the desert Southwest is experiencing resource constraints and other utilities are declaring energy emergencies, is the result of prudent planning and significant investments over time. We have installed and maintained equipment and technology capable of managing an increasingly complex energy grid. Our investments help build resilience, integrate clean energy, and support the continued growth of Arizona, all with the goal of keeping costs affordable for customers.

For example, we invest in core equipment and critical infrastructure, like network protectors, which provide backup power feeds to community-essential businesses like hospitals. In addition, APS continually monitors the health of its equipment, like aging poles, conductor, and cables, to identify indications of failure and replace the equipment, when appropriate, to reduce the potential for failure. We also plan for increased energy needs and invest in new substations in areas with projected growth. To reduce the potential for and impact of outages for customers, we deploy Advanced Grid Technology (AGT) to provide automatic response to frequency and voltage irregularities. Mr. Tetlow discusses these programs and investments in further detail in his testimony.

We know customers are counting on us more than ever before. We are committed to supporting them with modernized infrastructure capable of delivering the energy they need when they need it.

Q. WHAT STEPS IS APS TAKING TO KEEP UP WITH CUSTOMER GROWTH?

A. Arizona continues to experience high net migration into the state. Compared to the rest of the United States in 2021, Arizona was the third fastest growing state, Phoenix was the second fastest growing Metro area, and Maricopa County was the fastest growing county according to the United States Census Bureau. The record housing permits in Maricopa County demonstrate that residential growth is the highest since before the Great Recession. All this while customers are becoming more dependent than ever before on reliable electricity to power their lives. Commercial and industrial growth is also significant as Arizona has become a data center, manufacturing, and semiconductor hub. This commercial growth brings significant new jobs to the state in addition to significant energy load requirements and infrastructure investment from our Company. When neighborhoods expand, new residential developments are built, and when businesses relocate to Arizona or want to expand, our job is to make sure that the electric grid has the capacity to respond.

We plan years in advance to meet the needs of customers. Unlike commodities or other services, the service we provide requires instant availability to customers at the time they need it. Therefore, it is critical to make substantial capital investments and to seek reasonable and timely recovery of those investments such as we are doing in this rate case. One of our most important responsibilities is planning for future energy demand. We carefully forecast customer growth, and energy growth,

and systematically adjust our plans for grid investments to ensure we can serve customers reliably during extreme conditions.

Q. WHAT CHALLENGES DOES GROWTH POSE FOR APS?

A. Growth helps keeps rates low because it allows us to spread existing fixed costs over a larger number of customers, thus putting downward pressure on rates. However, the rapid growth that we are facing in our service territory requires APS to invest significant amounts of capital into the grid to ensure reliability and resiliency. Funding these investments at reasonable terms presents a formidable challenge for the Company. APS does not believe that under existing rates we have an opportunity to recover our costs and earn a reasonable return on investment. Securing the relief requested in this rate case in a timely manner is critical to being able to obtain needed financing at reasonable terms.

Q. EVEN WITHOUT GROWTH, WOULD APS STILL NEED TO INVEST IN NEW ENERGY INFRASTRUCTURE?

A. Yes. Growth is one driver for our infrastructure investment needs, but we also continuously assess the health of our aging infrastructure and replace or upgrade this equipment to ensure energy security and resiliency during extreme temperatures. For example, we maintain a host of maintenance programs to predict equipment failure and proactively replace aging equipment before it disrupts service for customers. Likewise, we invest in modernizing the grid to help detect and restore outages remotely to minimize the outage duration and frequency for customers. We also invest in modernizing our power plants to create greater efficiency in the output and preserve the functional life of the assets. All of this is described in more detail in Mr. Tetlow's testimony highlighting our reliability and PTYP investments.

Q. WHAT IS ENERGY RESILIENCY AND HOW DOES APS ENSURE A RESILIENT GRID?

A. As customers increase their dependency on electricity to power their homes and businesses, APS designs and builds the grid to meet the changing customer usage. For example, customers are now adopting electric vehicles at a faster rate than ever before which requires us to ensure our customers can charge their vehicles without impacting reliability. Our customers also continue adopting rooftop solar systems at record levels. These systems use the grid every minute they operate, often with two-direction power flow, and therefore need an electric grid that is capable of accommodating this fluctuating voltage, current, and frequency.

We're also experiencing more extreme weather conditions than previous years, which requires greater investment to maintain reliable service by hardening the system against weather impacts and repairing equipment damaged during events. For example, in 2020 we had the hottest summer on record, adding stress to the grid beyond typical planning criteria. In 2022, we experienced more severe monsoon storms than prior years which required more repairs to infrastructure than normal. Specifically, the summer storm season of 2022 required more than 800 pole replacements, compared to an average of roughly 250 poles replaced over each of the prior five summers. In order to continue serving customers reliably, we must design and build the grid to meet our customers' needs during these extreme conditions while also ensuring we can accommodate the changing electrification needs of our customers.

VI. SECURING A CLEAN, BALANCED ENERGY SUPPLY FOR ARIZONA

Q. ARE THERE RESOURCE CONSTRAINTS IN ARIZONA AND WITHIN THE WESTERN GRID?

A. Yes. Customer demand has increased faster than new resources have been built, and the existing supply of generation capacity in the west has been fully committed. Additionally, extreme heat during the past three summers has contributed to an even more challenging energy market throughout the Southwest. The lack of available capacity and resulting declarations of energy emergencies by other balancing area authorities across the west has provided a reminder of the importance of long-term resource portfolio planning, vigilance over day-to-day energy supply, and responsible energy policy.

Q. WHAT IS APS DOING TO ENSURE ENERGY SECURITY AS THE RESOURCE CONSTRAINTS IN THE WEST CONTINUE?

A. APS has been able to avoid energy emergencies during these extreme heat events because of careful long-term planning, prudent investments in resource adequacy, and flexibility stemming from a balanced and diverse resource portfolio. As described in Mr. Joiner's testimony, APS plans to acquire more than 2,300 MW of on-peak resource capacity by 2026 to ensure customers continue to experience reliable and affordable electric service. These investments will increase Arizona's energy security, reduce dependence on market purchases when other entities are experiencing energy emergencies, and protect customers from fuel-related price volatility. The requests in this rate case provide the revenue needed to continue this operational excellence and high-quality service for our customers.

Q. HOW IS APS INCORPORATING CLEAN ENERGY INTO ITS RESOURCE SUPPLY WITHOUT SACRIFICING AFFORDABILITY AND RELIABILITY?

A. APS is proactively seeking to obtain and integrate clean energy into our system in a way that will focus on affordability and reliability by balancing investments that optimize existing resources with investments in Arizona.

Because there is a scarcity of generation capacity in the desert Southwest needed to meet increasing demand, it is even more important for APS to use a range of strategies to meet customer needs. As we seek to meet these needs, investments in utility-scale clean resources are affordable and reliable, and provide the greatest value over their lifetime.

The decisions we make to invest in clean energy are made through a competitive procurement process. Clean resources are among the lowest cost options available today. Over the long term, these investments also provide the greatest value as a result of many factors.

For example, over the long-term, clean energy resources have a lower cost to own and operate than other resources. They are less dependent on operating and labor costs, water resources, and imports or transportation of fuel – all of which are ongoing, and sometimes have unpredictable costs. Clean energy investments are also uniquely positioned to take advantage of government benefits, including tax credits. These benefits reduce the overall costs of investing in additional capacity. Investments in clean energy also benefit from a lower cost of capital than other resources, as investors, credit rating agencies, and major lenders continue to use environmental, social, and governance criteria (ESG) in their decision-making

processes. All these financial benefits result in lower costs to customers. Mr. Cooper discusses this further in his direct testimony.

Beyond cost savings and avoidance, investments in clean energy also create greater stability and predictability in near-term costs for customers by reducing dependency on fuel and variable expenses that can fluctuate – often dramatically – over time.

Likewise, investing in clean energy supports a balanced and diverse energy portfolio which improves reliability and affordability by limiting the risk of any single source of energy and stabilizing costs during periods of volatility. Our existing resources, such as our natural gas generators, and Palo Verde Generating Station (the nation's largest producer of clean energy), complement these investments through continued support of customers' peak energy needs and are key to a diverse portfolio. As such, maintaining and expanding dispatchable resources in our generation fleet will continue to be a critical piece of our strategy to maintain affordability and reliability through a responsible and gradual transition to a clean energy future.

VII. THE IMPORTANCE OF ADJUSTMENT MECHANISMS

Q. WHAT IS AN ADJUSTMENT MECHANISM?

A. Adjustment mechanisms are a critical part of meeting the needs of customers and achieving our commitments to them. An adjustment mechanism is a regulatory-approved recovery plan specifically designed to address certain types of costs incurred by the electric company to serve its customers. APS's adjustment mechanisms recover costs that fluctuate between general rate cases and, with Commission approval, are addressed outside of our rate cases. They are

instrumental in achieving timely cost recovery, less frequent rate cases, and rate gradualism.

As the Commission has recognized, adjustment mechanisms provide substantial benefits to APS customers. These mechanisms fund important energy efficiency, demand response, and renewable energy programs. They provide customers with more timely return of savings when costs are reduced and when cost savings initiatives are implemented. They also help protect customers by facilitating more timely recovery of increased costs, including those related to necessary infrastructure investment, thereby keeping utility rates reasonable over time, and smoothing out the impacts of inflation and rising costs in addition to reducing credit risk, which lowers the cost of capital.

Adjustment mechanisms are widely accepted and utilized throughout the country and are considered to be sound regulatory policy. They are indicative of a positive regulatory environment, and help lessen APS's cost of financing, which in turn lowers costs to customers.

Q. PLEASE DESCRIBE APS'S CURRENT ADJUSTMENT MECHANISMS.

A. APS currently has seven Commission-approved adjustment mechanisms as described in Figure 4 below.

Figure 4. Current Adjustment Mechanisms at APS

EIS	The Environmental Improvement Surcharge (EIS) provides for the recovery of the capital carrying costs associated with qualified environmental improvement investments made by APS and not already recovered in base rates. These are projects at APS' generation facilities designed to comply with environmental standards mandated by federal, state, tribal, or local laws and regulations.
LFCR	The Lost Fixed Cost Recovery (LFCR) adjustor recovers the approved fixed cost of providing service to customers (power poles, wires, and other delivery infrastructure) that is not recovered between rate cases due to mandated energy efficiency and distributed generation programs.
TCA	The Transmission Cost Adjustment (TCA) provides a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission (FERC) and at the same time as new transmission rates become effective for APS wholesale customers.
DSMAC	The Demand Side Management Adjustment Charge (DSMAC) recovers costs for customer-focused energy efficiency and demand response programs that allow customers to reduce energy use and lower bills. Programs are approved by the Commission and comply with Arizona's Electric Energy Efficiency Standard.
REAC	The Renewable Energy Adjustment Charge (REAC) recovers the cost of Commission-approved renewable resources and customer programs to comply with Arizona's Renewable Energy Standard.
PSA	The Power Supply Adjustment (PSA) allows the Company to pass through to customers fluctuations in fuel, purchased power, storage product costs, off-system sales, and chemical costs.
TEAM	The Tax Expense Adjustment Mechanism (TEAM) allows the Company to pass through to customers income tax effects resulting from federal or state income tax legislation.

The TEAM is currently inactive and set at zero in accordance with Decision No. 78317.

APS's adjustment mechanisms were each created either in a rate case or by Commission rule and are governed by a Commission-approved Plan of Administration that requires annual or other periodic reporting for review by the Commission.

Q. WHY IS APS PROPOSING CHANGES TO ITS ADJUSTMENT MECHANISMS?

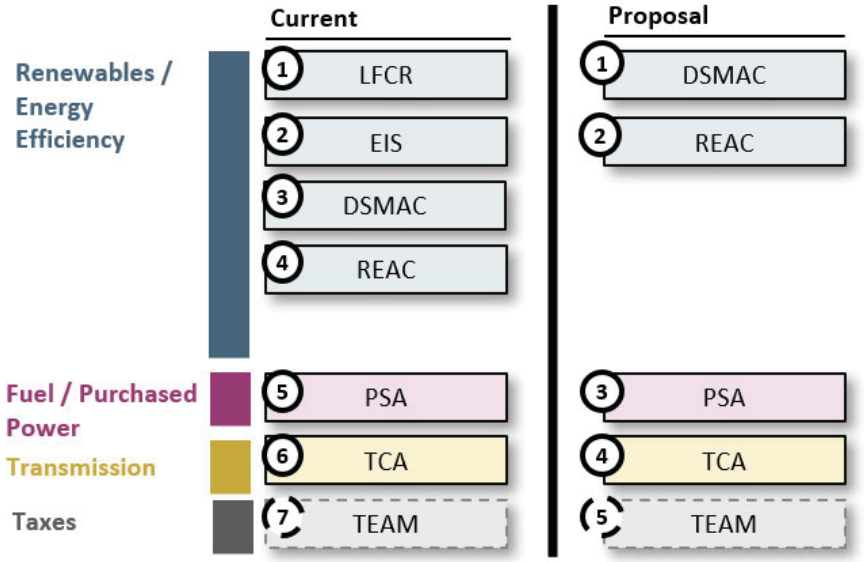
A. APS proposes a number of changes to its adjustment mechanisms, partially in response to the Commission's comments regarding the number of adjustment mechanisms employed by utilities and the impact of annual adjustor rate changes on customers. In the Company's last rate case, APS was ordered to meet with the Residential Utility Consumer Office (RUCO), Commission Staff, and interested stakeholders to develop a joint proposal or multiple proposals for modification, elimination, and/or consolidation of APS's adjustment mechanisms.

APS held collaborative meetings with stakeholders in April and May of 2022 to discuss potential modifications to APS's adjustment mechanisms. While unanimous agreement was not reached prior to this filing, APS is committed to engaging in collaborative stakeholder efforts throughout the course of this rate case.

Q. PLEASE PROVIDE AN OVERVIEW OF APS'S ADJUSTMENT MECHANISM PROPOSAL.

A. APS is proposing to reduce its current seven adjustment mechanisms to four active and one inactive adjustment mechanisms. Figure 5 below shows the current mechanisms and the Company's proposal, after which is a summary of the proposal.

Figure 5. APS's Adjustment Mechanism Proposal



First, APS proposes to eliminate the EIS adjustment mechanism entirely. In the future, costs currently eligible for recovery through the EIS will be handled through the traditional rate case process. Second, APS proposes to eliminate the LFCR mechanism. The costs eligible for recovery through the LFCR are proposed to be recovered partially in base rates and between rate cases in a revised DSMAC mechanism. Third, APS proposes to modify the REAC to include recovery of the capital carrying costs of future in-service APS-owned clean energy and energy storage resources (excluding nuclear energy). No structural changes are proposed for the TEAM, which is currently inactive and set at zero, or the TCA adjustment mechanisms.

The detailed impact of each of these proposals to APS's requested revenue requirement is discussed by Ms. Hobbick. Ms. Hobbick also calculates the impact of these proposals to APS customers and includes revised Plans of Administration for each of the modified adjustment mechanisms as attachments to her testimony.

Q. IS APS PROPOSING ANY ADDITIONAL CHANGES RELATED TO ITS ADJUSTMENT MECHANISMS?

A. Yes. In conjunction with the proposed move from seven to four active and one inactive adjustment mechanisms, APS also reviewed the filing and effective dates of the remaining four active adjustor rates with the goal of reducing and consolidating the number of times per year that customers experience adjustor resets. APS proposes to file its required RES and DSM plans in November of each year and requests that the annual resets for these adjustors occur the following October. The October effective date for DSMAC-1 and REAC-1 provides ample time for Commission Staff, interested parties, and the Commission to review implementation plans, and ensures that any customer bill impacts related to approved adjustor rate changes would be implemented outside of high energy use months. APS does not propose any changes to the filing and effective dates for the PSA and the TCA adjustor rates.

Q. HOW WILL APS'S ADJUSTMENT MECHANISM PROPOSAL BENEFIT CUSTOMERS?

A. Customers will benefit from the Company's proposed adjustment mechanism modifications in several ways. First, customers will benefit from fewer adjustment mechanisms on their bill, which will make it easier to understand their charges each month with minimal overall impact to their bill. Second, customers will benefit from a reduced number of times that their rates change throughout the year by changing the effective dates for certain adjustors. Third, customers benefit from rate gradualism, which helps spread the cost of investment over time versus a higher increase as part of a rate case and reduces the frequency of rate case requests. Customers will also receive the benefits of tax credits matched with concurrent resource recovery, thus providing more timely benefit to customers. Finally, the

proposals help to reduce the Company's credit risk, which makes access to low-cost capital more readily attainable, which helps control costs for customers.

Q. WHAT ARE THE CUSTOMER BENEFITS FROM INCLUDING RECOVERY OF APS'S CLEAN ENERGY INVESTMENTS IN THE REAC?

A. APS is proposing that capital carrying costs on its renewable energy and storage investments be recovered through the REAC. Similar costs associated with Purchase Power Agreements (PPAs) are already being recovered through the Company's PSA and REAC mechanisms. APS's proposal will simply put cost recovery of Company-owned clean energy and storage investments on equal footing with the recovery of those PPA associated costs.

As technologies develop and procurement opportunities expand for clean energy and storage resources, it is in our customers' best interest that there not be any artificial barriers to choosing between utility-owned investments or third-party PPAs. The current disparity in cost and investment recovery between utility-owned and third-party PPAs is one such barrier that could cause unintended consequences.

For example, and as explained in more detail by Mr. Cooper, the 2022 Inflation Reduction Act (IRA) will provide additional customer benefits including Production Tax Credits (PTC) for solar investments. Including the PTC as part of the carrying costs recoverable through the REAC would better match the tax benefits with asset recovery, thereby enabling our customers to realize these benefits sooner.

This need for recovery and optionality parity is significant. Today we anticipate a baseline need for almost 2,300 MW of additional on-peak resource capacity by 2026, a significant portion of which would be investments in clean resources.

APS is further proposing guardrails to protect customers and ensure the prudency of projects that would be recovered in the REAC. These guardrails include an annual earnings test and a requirement that the included resources must be acquired through an All-Source request for proposal (RFP) and be consistent with the Company's IRP Action Plan. Clean investments are capital-intensive up front, but feature substantially reduced lifetime operations and maintenance costs as well as no fuel expenses. APS's REAC recovery proposal will allow for its clean energy and storage investments to be more gradually included in rates, which will benefit our customers. Mr. Joiner will describe APS's evaluation process for PPAs and APS owned resources.

Q. ARE INFRASTRUCTURE-RELATED ADJUSTMENT MECHANISMS IN USE TODAY?

A. Yes. Infrastructure-related adjustment mechanisms, such as APS's proposed modification to the REAC, effectively allow defined assets to be included in a utility's rate base between rate cases and are increasingly being utilized. These mechanisms contribute to predictable and timely cash flows, thereby supporting credit quality and reducing regulatory risk and costs to customers.

As shown in S&P Global, Regulatory Focus Topical Special Report, *Adjustment Clauses: A State by State Overview*, Attachment TNG-01DR, 13% of jurisdictions employ regulatory adjustment mechanisms that recover traditional generation costs, while 23% employ a regulatory adjustment mechanism that allows recovery of renewable and other non-traditional resource costs.

In a historical Test Year jurisdiction like Arizona, capital investment is increasingly hard to keep recovery from fundamentally lagging. A capital cost recovery mechanism for renewable generation supports cash flows needed for these investments while also providing more timely matching of the fuel savings customers receive through renewable investment.

Q. ARE ADJUSTMENT MECHANISMS VIEWED FAVORABLY BY THE INVESTMENT COMMUNITY AND WOULD INVESTORS VIEW THE APPROVAL OF APS'S PROPOSED MODIFICATIONS AS A POSITIVE REGULATORY OUTCOME?

A. Yes, investors view adjustment mechanisms favorably and would view the approval of APS's proposal as a positive outcome.

Investors recognize the benefits of adjustment mechanisms and are aware that the use of adjustment mechanisms is very common in the utility industry. Investors also understand that APS's adjustment mechanisms are consistent with similar mechanisms across the industry.

Rating agencies have noted that regulatory jurisdictions which recognize the positive impact of timely investment recovery to both customers and utilities in their decision making are those that will appeal to investors. Approval of infrastructure-related adjustment mechanisms encourages investment in clean energy generation. Regulatory and cost recovery predictability leads to decreased financial risk and strengthened investor confidence and would enhance APS's ability to access lower-cost debt and longer-term debt on behalf of customers. Ultimately, creditors, and investors view adjustment mechanisms positively, which can lead them to discount our debt, making investments recovered through this process more affordable for customers.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Regulatory Focus Topical Special Report

Topical Report

July 18, 2022

Adjustment clauses: A state by state overview

Russell Ernst, Principal Analyst, Brian Collins, Senior Research Analyst, and Monica Hlinka, Research Analyst

Contributors: Jim Davis, Lillian Federico, Lisa Fontanella, Jason Lehmann and Dan Lowrey

This report covers the key adjustment clauses used by the largest electric and gas utilities in the 53 jurisdictions covered by Regulatory Research Associates, a group within S&P Global Commodity Insights.

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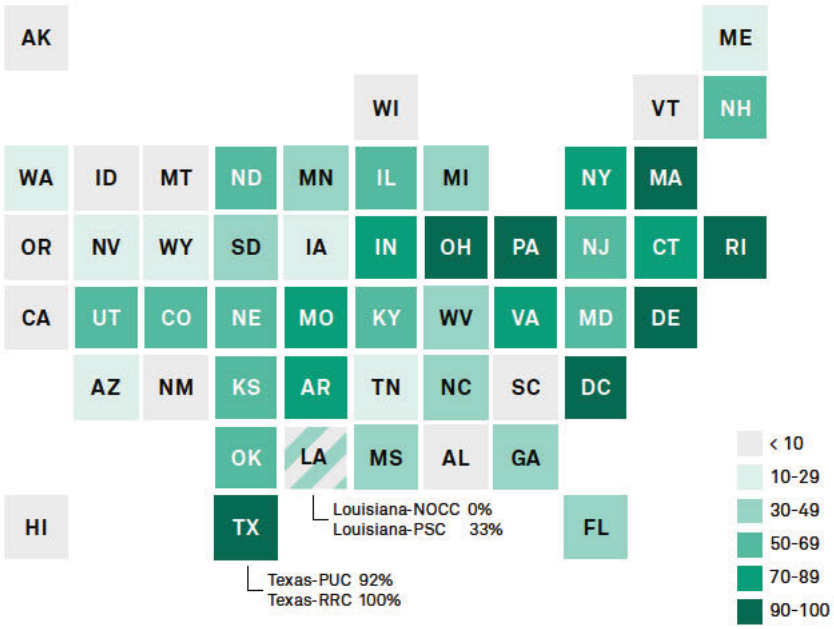
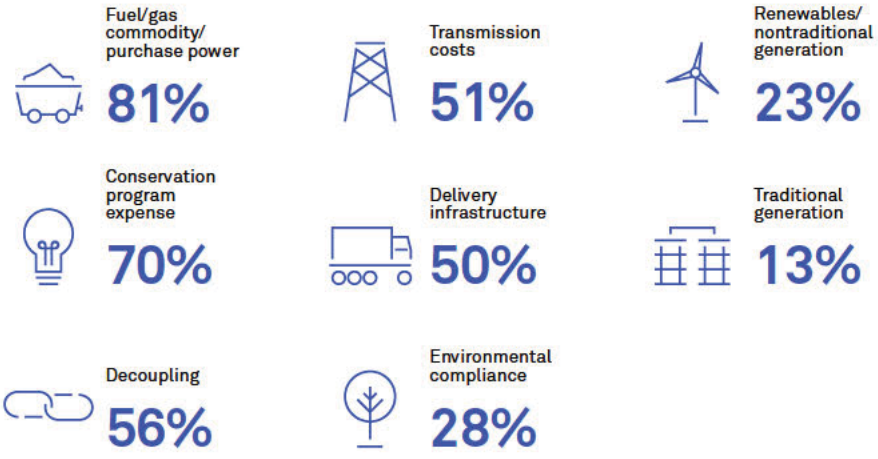
More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation or delivery infrastructure to be used, effectively including these items in rate base without the need for a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.

As shown in the following infographic, certain types of adjustment clauses are more prevalent than others. For example, those that address electric fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and roughly half of the utilities have some type of decoupling mechanism in place.

Utilities with adjustment clauses for delivery infrastructure (%)



Adjustment clauses in use (%)



Data as of June 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

DIRECT TESTIMONY OF JACOB TETLOW

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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ATTACHMENT LIST

Customer Technology Post-Test Year Plant Additions ..... Attachment JT-01DR

IT and Facilities Post-Test Year Plant Additions ..... Attachment JT-02DR

Nuclear Generation Post-Test Year Plant Additions ..... Attachment JT-03DR

Distribution Post-Test Year Plant Additions ..... Attachment JT-04DR

Other Generation Post-Test Year Plant Additions ..... Attachment JT-05DR

Renewable Generation Post-Test Year Plant Additions ..... Attachment JT-06DR

Agreement Between the Navajo Nation and Arizona Public Service Company Regarding Coal-Community Transition ..... Attachment JT-07DR

DIRECT TESTIMONY OF JACOB TETLOW
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jacob Tetlow. I am Executive Vice President of Non-Nuclear Operations at Arizona Public Service Company (APS or Company), and my business address is 400 N. 5th Street in Phoenix, Arizona.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I earned a Bachelor of Science in Mechanical Engineering from Arizona State University and worked as an engineer and power plant supervisor prior to joining APS in 2001. During my years at APS, I have held various frontline and leadership positions including Production Manager at the Company's Cholla Power Plant, Director of Gas and Oil Generation, Director of Coal Generation, Director of Distribution Operations and Maintenance, General Manager of Transmission and Distribution Operations, Vice President of Transmission and Distribution Operations, and Senior Vice President of Operations (Non-Nuclear). I was named to my current position, Executive Vice President of Non-Nuclear Operations, in May of 2021.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I oversee more than 2,600 of APS's union and non-union employees who ensure the safe, reliable, and efficient generation and delivery of electricity service, along with numerous related operations. In sum, these operations include:

- The Company's non-nuclear generation fleet, including renewable generation;
- APS's energy delivery function, which includes system operations, maintenance, engineering, and construction of the transmission and distribution system;

- The Company's resource management organization, which includes integrated resource planning, resource procurement, and marketing and trading functions;
- Operations support services, including environmental, facilities, transportation, customer to grid solutions, and corporate safety and security; and
- APS supply chain management functions, including procurement, warehousing, and logistics.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. Yes. I provided testimony in the Company's rate case filed in 2016 and in the Company's last rate case filed in 2019. I have also participated in numerous workshops, open meetings, and other proceedings at the Commission.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My Direct Testimony supports the Company's post-Test Year plant (PTYP) request, and APS's Coal Community Transition (CCT) proposal. I will also discuss electric vehicle (EV) infrastructure efforts underway in support of the Statewide Transportation Electrification Plan, along with other generation and non-generation infrastructure investments projected to be necessary for APS to implement its 2050 Clean Energy Commitment.

II. SUMMARY

Q. WHAT IS APS'S OVERALL APPROACH TO ENSURING SAFE OPERATIONS?

A. Ensuring the protection of APS's customers, Company employees, and the communities where the Company operates is a number one priority. APS implements numerous programs aimed at ensuring that the Company's work is

performed safely. Based on the metrics APS uses to evaluate safety performance, the Company has been successful in maintaining a safe work environment. Nonetheless, APS's commitment toward continuous improvement for the safety and well-being of its employees persists to ensure that all employees return home safely every day.

Q. PLEASE SUMMARIZE YOUR POST-TEST YEAR PLANT DIRECT TESTIMONY.

A. Meeting the needs of customers requires APS to continue to invest in and maintain the energy grid, along with APS's existing nuclear and non-nuclear generation resources. For these reasons, I describe how APS's PTYP investments, anticipated to be placed into service between July 1, 2022 and June 30, 2023, build resilience, ensure around-the-clock reliability, enable APS to integrate more and different sources of clean energy, and support the continued growth of Arizona. Because of investments like these, APS is proud to be recognized as one of the most reliable electric providers in the country. My testimony describes how APS's ability to deliver reliable service today is the result of significant investments over time to install equipment and advanced technology capable of managing an increasingly complex and robust grid that is subject to regular threats from Arizona's extreme weather and rugged terrain.

My testimony also describes PTYP investments and other Company initiatives aimed at improving the customer experience. These investments enhance APS's ability to meet the needs of its customers, while also bringing advanced technology to its customers' doorstep through programs designed to serve a growing diversity of electricity needs. These resources, such as EV charging infrastructure, distributed solar and energy storage, energy efficiency, peak demand management, and microgrid products, will be increasingly critical to maintaining a reliable and

resilient system, while at the same time providing customers with greater control over their energy usage and bills. Additionally, I will describe how these investments substantially increase APS's cost-effective deployment of renewable resources coupled with energy storage, which will create a more balanced and diverse energy resource portfolio for APS's customers. By doing so, these investments will reduce customer exposure to the volatile pricing of fuels sourced from outside of the state.

III. SAFETY

Q. PLEASE DESCRIBE THE IMPORTANCE OF SAFETY AT APS.

The first and highest priority for all APS employees is to work safely. Safety is especially important for many Transmission and Distribution (T&D) employees who routinely work with lines and facilities that are either energized or may become energized at a moment's notice and Generation employees who work within complex, rotating and high energy machinery to provide around the clock energy for customers. APS has a rigorous safety program and Safety Management System in place and continually looks to improve the effectiveness of its safety culture and ensure regulatory compliance.

The industry best practice to measure serious safety events and ensure the Company performs well in protecting employees from life altering injuries is the number of Serious Injuries or Fatalities (SIFs). The SIF metric is the Company's most important safety metric and is focused on preventing serious injuries by improving hazard recognition, risk-based decision making, procedures, equipment selection, employee training, and much more. In each case, the SIF metric helps ensure that APS's work is completed safely for its customers, employees, and the communities the Company serves. APS, along with the utility industry, has successfully driven down the number of overall injuries and Occupational Safety

and Health Administration (OSHA) recordable injuries in the past decade. APS and its peers are increasingly focused on reducing or eliminating these life altering injuries.

APS also recognizes its responsibility to its customers and the public to create a safe environment when providing electric service. This responsibility translates into a variety of concrete actions, from safely maintaining the substations to patrolling both T&D lines to detect and repair unsafe conditions. If the Company receives a call from a customer with a safety-related concern regarding APS's service facilities, employees are dispatched immediately to assess the situation and take any action needed to create a safe environment, including repairing, replacing, or de-energizing facilities if needed.

APS takes its responsibilities interacting with the public seriously. APS employees support ongoing outreach to the community, first responders, and third-party contractors through various means. APS continues to deliver electricity education to community and school groups through its traveling Electric Safety Trailer presentations. APS engages first responders through re-occurring energy training and training on how to respond when there is an event near APS's facilities.

Q. WHAT ARE SOME OF THESE SAFETY PROGRAMS?

A. Investment in safety—both employee and public safety—is a top priority. Employees participate in regular training programs throughout the year. These programs include those that increase skill sets, improve crew safety, efficiency and planning, or familiarize field personnel with new equipment and procedures.

In March 2020, APS launched the SAFE mobile app to enable field personnel to conduct Pre-Job Briefs, facilitate engaging safety discussions, and provide access

to safety and human performance tools. This provides accurate access to employees at their fingertips, including the most current version of the Accident Prevention Manual, allowing improved version control and access to the newest updates.

Building on APS's strong safety foundation, Safety Forward is a systems-focused program that looks to improve human and organizational performance education and communication, build safe work ownership, and employee trust. The Safety Forward program focuses on metrics that matter, such as leading indicators and high energy sources, which more closely align with the industry's best practices on continuous improvement of safety.

In support of Safety Forward and APS's focus on SIF injuries, APS has integrated Edison Electric Institute's (EEI) Safety Classification and Learning Model (SCL) which has a strong focus on events where high energy is present. This program provides a framework for categorizing all events to complete the appropriate level of analysis to address high energy controls and work to prevent event re-occurrence. This program has been incorporated into APS's foundational systems to get full visibility to SIFs, potential SIFs and Exposure events. More than 3,800 of APS's employees have been trained in this program to date.

In summary, the safety-related programs and initiatives discussed above are founded in providing employees the right training, tools, and overall environment to keep themselves, their team members, and the public safe at all times.

Q. HAVE THESE PROGRAMS BEEN SUCCESSFUL?

A. Yes. APS's safety programs demonstrate that the Company's commitment to continuous improvement, safety education, and performance programs continue to make a significant impact on the safety and well-being of APS's employees. APS

emphasizes safety accountability at all levels of the organization, a continual focus on identifying and eliminating safety risks, and a strong management and employee commitment to safety. It is critical that APS's employees go home in the same condition they came to work, returning safely to family and friends.

IV. RELIABILITY

Q. PLEASE PROVIDE AN OVERVIEW OF APS'S SERVICE TERRITORY AND INFRASTRUCTURE.

A. APS's service territory covers nearly 35,000 square miles and is one of the most geographically diverse regions which includes a variety of elevations, climates, and jagged terrains that can be challenging to navigate. To provide this service, APS uses infrastructure that includes:

- Approximately 33,000 miles of distribution lines;
- Over 6,000 miles of transmission lines;
- Nearly 500 substations;
- Roughly 300,000 transformers; and
- More than 550,000 power poles and structures.

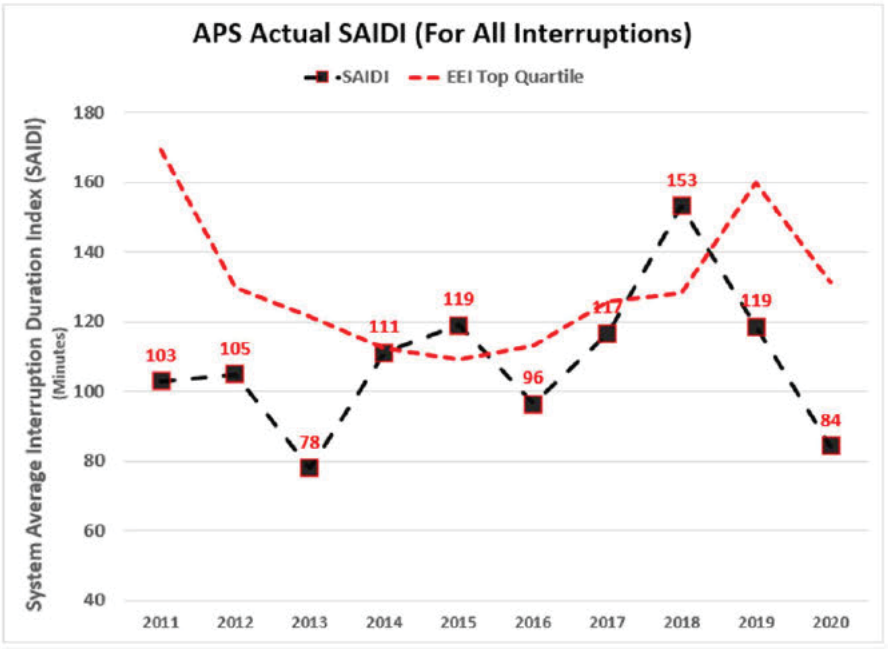
From canyons to forests, deserts to metropolitan cities, APS provides electricity across a range of climates and landscapes. This expansive infrastructure must be resilient to maintain reliable service in the face of regular threats posed by various extreme weather events. Despite these challenges, APS continually strives to ensure reliable service and meet customers' needs.

Q. HOW DOES APS DETERMINE THE SUCCESS OF RELIABILITY?

A. APS consistently delivers at or better than annual EEI top quartile reliability, including achieving top quartile System Average Interruption Duration Index (SAIDI) for eight out of the last ten years and, System Average Interruption

Frequency Index (SAIFI) performance nine out of the last ten years, for which finalized data is available (as shown below in Figures 1 and 2):

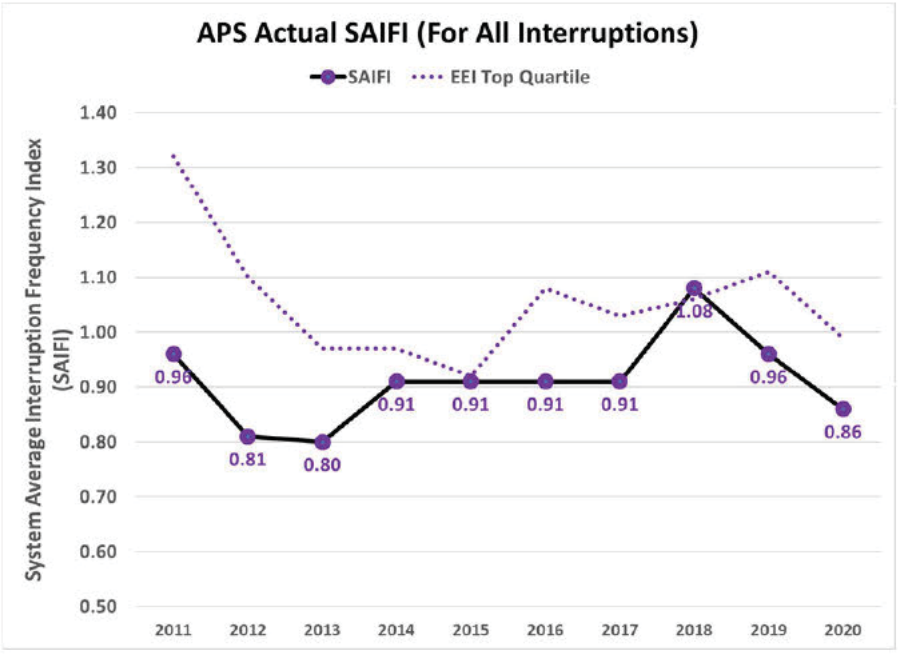
Figure 1: SAIDI 10 Year Trend



A lower number equals better performance



Figure 2: SAIFI 10 Year Trend



A lower number equals better performance



Additionally, APS was ranked in the top five among all U.S. utilities for "Perfect Power" at the end of 2021. This measure in the J.D. Power residential survey is defined as a customer not recalling any brief or sustained outages in the last three months.

Q. WHAT ARE SOME OF THE STRATEGIES USED TO IMPROVE RELIABILITY?

A. APS has conducted enhanced line patrols, removed over 1,968 at-risk hazard trees outside the Company's rights-of-way in 2021, and conducted various distribution upgrades on poles, cross arms, reclosers, fault indicators, fuses, etc. Along with its extensive vegetation management program that keeps APS's rights-of-way clear, the Company has a comprehensive fire mitigation program. This includes creating a defensible space around 70,000 poles as shown in Figure 3 below. In practice this means ensuring there is a buffer—cleared of vegetation—around APS's T&D infrastructure, removing wildfire fuel from these areas. Collectively, these efforts not only harden APS's infrastructure but also mitigate the risk of wildfires.

Figure 3: Defensible Space Around a Pole Near the Montezuma Well Area



Another strategy is APS's enhanced pole inspection program. APS inspects aged wood poles at routine intervals as they reach the end of useful life and replaces them with new wood or steel poles as appropriate. APS regularly inspects its distribution infrastructure, looking for potential key public safety and reliability related issues while making necessary repairs. In addition to enhanced pole inspections, APS also updated its distribution power line reclosing strategy to provide enhanced system protection during elevated fire conditions on high-risk feeders.

V. CLEAN ENERGY TRANSITION SYSTEM UPGRADES

Q. WHAT ARE THE TRANSMISSION SYSTEM UPGRADES AND EXPANSIONS THAT APS ANTICIPATES IN ORDER TO PREPARE FOR FUTURE CUSTOMER NEEDS ARISING FROM LOAD GROWTH, INCREASED ELECTRIFICATION, AND THE DELIVERY OF ADDITIONAL CLEAN GENERATION RESOURCES?

A. APS's 2022-2031 Ten-year Transmission System Plan (Ten-year Plan), filed with the Commission on January 31, 2022, identifies the Company's major transmission projects planned during that timeframe, inclusive of customer load growth, electrification, and the incorporation of new generation resources. As described in the Ten-year Plan, APS plans to invest about $914 million in new transmission construction and upgrades from 2022-2031. With this investment, the Company expects to build about 68 miles of new transmission lines and upgrade about 13 miles of transmission lines, and install and upgrade transformers, reactors, and capacitors. The projects included in the Ten-year Plan are intended to address various factors influencing the transmission grid, such as load growth and generator interconnections.

In addition, APS recently filed a supplement to the Company's 2022 Ten-year Plan that identifies the emergent need for an additional approximately 135 miles of new transmission lines to meet growing electricity demand within APS's service territory. Cost estimates for these projects are not yet available. Of these projects, approximately 115 miles of the new transmission line construction identified in APS's 2022 Ten-year Plan supplement will facilitate greater western market access and integration for the benefit of APS customers, along with other customer-centric purposes. With Arizona being the third fastest growing state in the nation and home to the fastest growing county, Maricopa County, planning for and construction of

additional transmission line access to western regional electricity markets will help APS meet the increasing needs of customers for clean and reliable electricity. APS witness Justin Joiner discusses further the benefits to APS customers from increasing the Company's access to western electricity markets.

Q. WHAT ARE THE DISTRIBUTION SYSTEM UPGRADES AND EXPANSIONS THAT APS ANTICIPATES IN ORDER TO PREPARE FOR LOAD GROWTH, INCREASED ELECTRIFICATION, AND THE DELIVERY OF ADDITIONAL CLEAN GENERATION RESOURCES?

A. The Company's distribution system is growing and adapting to the realities of rapidly growing customer load—driven in part by expanded customer electrification of buildings and transportation—along with expanding solar distributed resource interconnections. APS engages in proactive planning procedures that strategically take these energy industry trends into account to provide reliable and affordable service for customers.

For example, APS carefully plans for the inclusion of distribution-side generation resources to optimize grid management. APS-owned resources, such as those installed under the Company's Solar Communities Program (both commercial scale and residential scale systems), are strategically placed on feeders that have available hosting capacity or could benefit from a new, distributed resource. In addition, APS can control the power output from the inverters on these resources to maintain grid stability on the line. As APS looks to the future, the Company anticipates that additional distributed demand side resources (DDSR) could play an important role in ensuring grid reliability. DDSR aggregation strategies have significant potential value in leveraging customer technology (such as home battery storage) to manage peak load and deliver other grid benefits for all APS customers.

For customer-sited distributed generation resources, such as rooftop solar, each application is evaluated to align with the Commission's interconnection regulations. APS works with customers to determine whether new customer-sited generation could exceed system limitations based on system size and orientation, and whether the system itself can be configured to control impacts. In these situations, APS considers a variety of solutions, including using advanced inverter settings and distribution feeder upgrades to account for additional distributed generation. APS continues to develop feeder-level forecasts for distributed energy generation so growth can be considered within the Company's distribution planning processes to sustainably integrate these customer-sited resources.

In addition to APS's robust planning processes, the Company continues to research new technologies aimed at modernizing the grid while maintaining reliability and alleviating some of the challenges that accompany increases in load growth, electrification, and distributed generation installations. One of the technologies APS uses to accomplish this is Advanced Grid Technologies (AGT), which allow for intelligent and remote control of the Company's distribution system. AGT improves grid automation to detect and isolate faults, reduce losses, improve customer voltage, and enable more distributed generation while reducing the need for human intervention. Distribution grid solutions such as AGT are just some of the many ways in which APS is looking to more efficiently manage the current distribution system to better accommodate load growth and expanding distributed generation resources.

Q. WHAT PLANS DOES APS HAVE TO EXPAND, CONVERT, AND/OR UPGRADE ITS GENERATING FACILITIES TO ACHIEVE A CLEAN ENERGY FUTURE?

A. As I will describe later, APS will be installing chillers at both Sundance and Redhawk power plants. The chiller projects will improve performance of the units at high ambient temperatures by pre-cooling inlet air when peak demand is highest and allow for increased power output during hot summer months and year-round. Increasing the output and efficiency from APS's existing gas resources enables the Company to install additional renewable resources, such as solar and wind, by ensuring dynamic responses to maintain grid reliability when variable and intermittent renewable resources are not available. The importance of gas resources in APS's transition to a clean energy future is more fully described in Mr. Joiner's testimony.

Q. IS APS REQUESTING RECOVERY OF THE UPGRADES AND EXPANSIONS REFERENCED IN THIS SECTION IN THIS RATE CASE?

A. As requested in Chairwoman Márquez Peterson's letter filed in this docket on June 2, 2022, APS is providing information related to system upgrades and expansions through 2035 but is not requesting recovery of investments expected to be in service after June 30, 2023 in this rate case.

VI. <u>POST-TEST YEAR PLANT ADDITIONS</u>

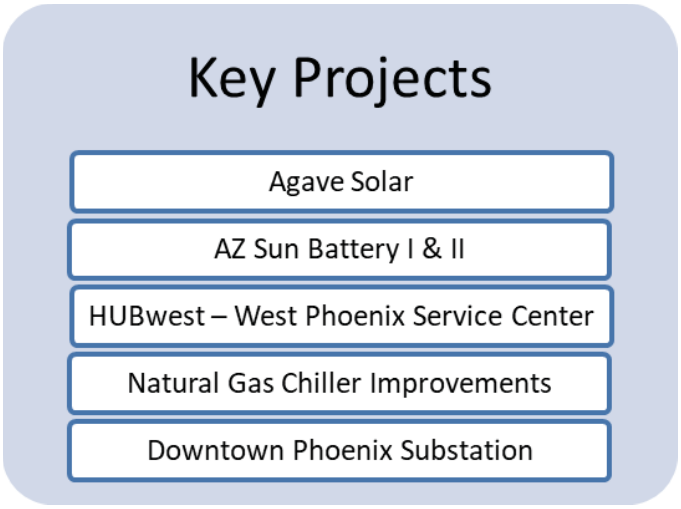
Q. WHAT IS APS'S PTYP REQUEST IN THIS CASE?

A. APS is requesting $1.5 billion in total Company gross capital expenditures for the 12-month period ending June 30, 2023, which is the 12-month period immediately after the Test Year in this case (*see* SFR Schedule B-2, pages 1-2, columns 1-6, and Attachments JT-01DR, JT-02DR, JT-03DR, JT-04DR, JT-05DR, and JT-06DR). In addition, APS will roll forward accumulated depreciation and taxes during the PTYP period, which further reduces its PTYP request by approximately

$680 million. Thus, APS is requesting $788.8 million be added to rate base. Largely, the investments that make up this request are focused on the following:

- Securing a clean and balanced energy supply for Arizona through investments in renewable energy and energy storage projects in addition to improvements to APS's existing generation resources;
- Improving the information technology and physical facilities that support efficient and safe work processes, while also making them more sustainable;
- Ensuring that Palo Verde Generating Station—the nation's largest power producer of any kind for nearly 30 years, all of it carbon-free—continues to provide safe and reliable service;
- Improving the resiliency, sustainability, and efficiency of APS's electricity transmission and delivery systems; and
- Ensuring that APS's non-nuclear generation provides efficient and top quartile performance that balances and maintains a reliable electricity grid.

Figure 4: Key Post-Test Year Projects



It is projected that all assets in the Company's PTYP request will be serving customers prior to the anticipated rate effective date in this case. APS will update

its request to reflect the actual cost of these investments as assets are placed into service during rebuttal testimony.

In accordance with Decision No. 76295 (August 18, 2017) and affirmed in Decision No. 78317 (November 9, 2021), APS has excluded all growth-related plant from its request.

Q. PLEASE DESCRIBE THE INVESTMENTS THAT HAVE BEEN INCLUDED IN APS'S PROPOSED PTYP.

A. The various projects included in PTYP are summarized by category below.

A. *Customer Technology Innovation*

Q. WHAT CAPITAL EXPENDITURES ARE INCLUDED IN THE PROPOSED PTYP RELATED TO CUSTOMER TECHNOLOGY INNOVATION?

A. The Company requests recovery of $16.8 million in capital spending for customer-based technology innovations. This includes expenses supporting clean, advanced-technology customer programs, such as $9.4 million for EV charging infrastructure, which supports statewide EV adoption goals and provides service for an ever-increasing customer demand. Additionally, this capital spending includes the development of a microgrid facility, which provides cleaner solutions for on-site back-up generation for critical infrastructure, while also enhancing system resiliency and service reliability for all APS's customers through enhanced grid frequency response and capacity values.

Q. WHY ARE EV INFRASTRUCTURE INVESTMENTS IMPORTANT?

A. As described in the Arizona Statewide Transportation Electrification Plan Phase I[1] report, "Transportation electrification can provide numerous benefits to EV drivers, utility customers, and the Arizona economy overall… reducing emissions

[1] Docket No. RU-00000A-18-0284, Arizona Statewide Transportation Electrification Plan: Phase I (Dec. 27, 2019) at 8.

of harmful air pollution, directly benefiting the health of all Arizonans." Further, several economic factors are also encouraging customers to switch from internal combustion engines to electric vehicles, including rising fuel costs and commitments from major auto manufacturers to increase production and availability of electric vehicles today and into the foreseeable future.

Q. ARE APS'S EV INFRASTRUCTURE INVESTMENTS SUPPORTIVE OF DECISION NO. 78383?[2]

A. Yes. The APS Take Charge AZ program is making level 2 (L2) and direct current fast charging (DCFC) available to APS's customers and is an important initiative supporting the Commission-approved 2030 adoption goal.

Q. ARE APS'S CUSTOMERS INTERESTED IN TAKE CHARGE AZ?

A. Yes. APS has installed EV chargers at more than 150 sites, making more than 642 new plugs available for customers in over 31 cities across eight counties within the state. Figure 5 below shows one of APS's DCFC locations in Show Low, Arizona.

Figure 5: APS DCFC Location in Show Low, Arizona



[2] Docket No. E-00000A-21-0104, Decision No. 78383 (Dec. 28, 2021).

Q. WHAT EFFORTS ARE UNDERWAY AT APS TO SUPPORT EV ADOPTION?

A. As outlined in the Arizona Statewide Transportation Electrification (TE) Plan Phase II[3] and listed in Decision No. 78383 (December 28, 2021), APS has begun or is planning various initiatives to support and encourage EV adoption within its service territory in support of the 2030 goal. A sample of these efforts are shown in Figure 6 below.

Figure 6: EV Adoption Barriers & APS Initiatives

Barrier	APS Initiatives
Inequity in TE Planning	• Regular TE Collaborative meetings with stakeholders
Education and Outreach	• APS Marketplace; improving APS EV website • Take Charge AZ (L2 and DCFC installation and ownership)
Access for Underserved Communities	• Take Charge AZ (L2 and DCFC installation and ownership)
Insufficient Charging Infrastructure	• Take Charge AZ (L2 and DCFC installation and ownership) • New EV pre-wire incentive • TRU [Truck Refrigeration Units] and electric forklift incentive
Grid Planning and Capacity Needs	• EV adoption forecasting • Charging analysis • Load forecasting using residential EV charging data

[3] Docket No. RU-00000A-18-0284, Arizona Statewide Transportation Electrification Plan: Phase II (April 1, 2021) at 69-72.

Q. BEYOND THE POST-TEST YEAR, WHAT OTHER LONG-TERM BENEFICIAL ELECTRIFICATION AND ENERGY EFFICIENCY MEASURES ARE APS PLANNING THAT WILL HELP ACHIEVE ARIZONA'S CLEAN ENERGY FUTURE?

A. Customer-sited resources will become an increasingly important part of the energy mix on APS's pathway to serving its customers' needs with 100% clean energy resources. APS will continue to propose new and innovative customer programs that are focused on energy efficiency, beneficial electrification, demand side management (DSM), peak load management, demand response, and device aggregation. Rapidly scaling the Virtual Power Plant of connected devices is proving to be more and more important, and APS is actively evaluating ways to fully leverage available and evolving technology to provide maximum value to the system on the hottest days of the year and other times when grid stress is the highest.

Currently, these investments are planned for in APS's Demand Side Management Implementation Plans and recovered through APS's Demand Side Management Adjustor Clause (DSMAC). Currently planned and future DSM initiatives include:

- Managed EV charging systems;
- Aggregated customer thermostats and HVAC controls;
- Interconnected customer battery energy-storage systems; and
- Expansion of DDSR initiatives for grid services.

B. *Information Technology and Facilities*

Q. WHAT CAPITAL EXPENDITURES ARE INCLUDED IN THE PROPOSED PTYP RELATED TO INFORMATION TECHNOLOGY AND FACILITIES?

A. The Company requests recovery of a total of $297.5 million in capital spending for Information Technology (IT) and Facilities. SFR Schedule B-2, page 2, column 4 combines Distribution and IT and Facilities investments.

The IT investments include upgrades to various systems to maintain operational support for reliable electricity deliveries and necessary enhancements to secure critical energy infrastructure for Arizona. This includes the Illuminate Advanced Apps project, a $15.3 million investment to upgrade the Advanced Distribution Management System (ADMS), which benefits APS's customers by providing more consistent voltage, reduced outages, and shorter durations to repair systems and resume service. In addition to software upgrades, APS also relies on IT improvements and modernizations to the physical infrastructure, which is critical to provide service to customers. APS invested $7.6 million in next generation Local Area Network communication equipment, which is APS's core data transport system that supports the Company's ability to control and safely operate the power grid. Also included is a $8.2 million investment in IT access management systems, which will improve the security of APS's infrastructure necessary for the delivery of reliable service. In each case, the investments are necessary to improve the reliability of APS's customer service by making the systems that customers depend on for energy delivery more secure and resilient.

The Facilities investments include necessary infrastructure upgrades for APS's physical buildings exclusive of generation, distribution, and transmission facilities.

These infrastructure upgrades are necessary for APS to continue safe and reliable business operations supporting generation and delivery of electricity for customers. This includes a $27.5 million investment for the new Cottonwood Service Center. The existing service center requires upgrades and is too small to support current warehousing and transportation needs. The new Cottonwood Service Center combines the Verde Valley transmission and distribution, transportation, supply chain, and IT operations into one site versus two and is designed to improve material handling operations. APS will be able to vacate two lease agreements with the building of the new service center. These investments are critical to ensuring that facilities necessary to support the reliable delivery of electricity to customers are resilient and can be operated cost-effectively. Also included in Facilities spend is a $128.7 million investment in the HUBwest project.

Q. PLEASE DESCRIBE THE HUBWEST PROJECT.

A. Located in Buckeye, the project will add warehouse, garage, and service center capacity to more quickly, safely, efficiently, and reliably serve customers in the area. The HUBwest project will bring added reliability to customers by increasing APS's capability to address system repairs, maintenance, and upgrades within the area. This investment will ensure that APS can more quickly and cost-effectively deploy resources to this part of APS's service territory that has experienced rapid growth. In addition, the HUBwest project will help create a safer, more efficient workplace for employees by improving material handling and storage and consolidating undersized and aging buildings.

C. *Nuclear Generation*

Q. WHAT CAPITAL EXPENDITURES ARE INCLUDED IN THE PROPOSED PTYP RELATED TO NUCLEAR GENERATION?

A. Palo Verde Generating Station is the largest producer of carbon-free electricity in the United States and these PTYP investments benefit customers by funding

necessary plant improvements enabling continued safe and reliable output from the foundation of Arizona's clean energy future and energy security. The Company requests a total of $63.4 million in nuclear generation capital expenditures. This request includes a $7.3 million investment to improve clarifiers within Palo Verde Generating Station's advanced water treatment infrastructure, which enables the plant to utilize recycled municipal wastewater for cooling and enhances the sustainability statewide. A $14.7 million investment to improve the Palo Verde Generating Station's cooling-water spray ponds will further enhance resiliency and safety of this critical generation asset. Also included is $16.3 million for the Strategic Modernization Program (SMP) which will replace several plant control systems, both analog and digital, with newly designed and upgraded equipment. This upgrade will address obsolescence, remove single point vulnerabilities where practical, improve Human-Machine Interfaces, and minimize spare part inventories.

D. *Distribution*

Q. WHAT CAPITAL EXPENDITURES ARE INCLUDED IN THE PROPOSED PTYP RELATED TO DISTRIBUTION?

A. The Company requests a total of $250.7 million in distribution capital expenditures. These expenditures are necessary to ensure safe, reliable, resilient energy delivery to customers through the Company's distribution system. This includes repairing distribution lines and poles that are damaged in extreme weather, substation improvement, and deployment of grid technology to improve service quality and reliability.

A key project in this category is the $50.5 million Evans Churchill substation upgrade project, which provides necessary improvements to critical systems supporting downtown Phoenix. This project replaces outdated substation

equipment with Gas Insulated Switchgear (GIS) that improves the capacity and reliability of downtown Phoenix. Additionally, this project prevents hazards in the event of equipment failure and ensures APS field personnel have proper safety clearances when performing work. This category also includes $18.7 million in AGT deployments providing automatic response to frequency and voltage irregularities, to minimize the potential for and impact of outages for customers. The distribution PTYP expenses also include significant planned replacements of aging infrastructure, including, but not limited to:

- Network protectors, which provide redundant, or backup, power feeds to critical customers like hospitals;
- Overhead line replacements for damaged, defective or failed overhead equipment; and
- Underground cable replacement for aged direct buried cable.

These investments directly benefit customers, not only by improving the resilience of existing lines, poles, and substations, but also through the incorporation of more advanced technologies enabling more efficient and cost-effective grid management.

E. *Other Generation*

Q. WHAT CAPITAL EXPENDITURES ARE INCLUDED IN THE PROPOSED PTYP RELATED TO OTHER GENERATION?

A. Other generation PTYP expenses represent $300.9 million of APS's overall PTYP request. These expenses include projects supporting the Company's entire non-nuclear and non-renewable generation portfolio. These expenditures are necessary to maintain and replace various equipment, such as pumps, valves, motors, breakers and additional electrical systems, and other critical operating equipment throughout APS's generation portfolio to ensure that its generating units will be available to serve customers when needed, to maintain and improve operating

efficiency and cost-effectiveness, and to maintain a safe work environment for APS's employees. For example, the investments include $105.1 million for the previously mentioned chiller projects that will improve performance of the Sundance and Redhawk power plants by allowing for increased power output during times of peak demand.

These expenditures also include environmental compliance and environmental equipment upgrade projects to continue APS's commitment to safe, reliable, and clean generation. For instance, APS is making modifications at the Four Corners Power Plant to comply with EPA's updated steam-electric power plant Effluent Limitation Guidelines (ELG). This $36.7 million project involves converting the existing plant coal-ash wastewater and low volume wastewater systems to a closed loop configuration, which will ensure zero-liquid discharges as part of normal plant operations. The investment in these modifications will ensure the plant is environmentally compliant and available to serve customer needs.

Q. IS APS PLANNING ANY FUTURE POLLUTION CONTROL AND ENVIRONMENTAL COMPLIANCE PROJECTS?

A. As APS continues to utilize its non-nuclear and non-renewable generation fleet as critical reliability resources for the foreseeable future, the Company will continue to improve the environmental performance of these facilities. APS's commitment to a clean energy future for Arizona extends beyond investing in clean resources; it includes ensuring that its current fleet of non-nuclear and non-renewable resources operate more sustainably. These are important investments to ensure these generating facilities maintain reliable and safe operations for customers, employees, and the communities in which APS operates. These investments include measures to enhance the protection of groundwater and surface water resources in the areas surrounding APS's facilities; improvements to APS's

infrastructure that manages facility water resources and more effectively convey wastewater; and enhancements to existing air emissions control devices to maintain compliance with air pollution control regulations and increase efficiency.

Q. HOW IS ONGOING PLANT OPERATIONS AND MAINTENANCE AFFECTED BY APS'S TRANSITION TO CLEAN ENERGY?

A. Investing in ongoing maintenance of APS's non-nuclear generation resources until retirement is essential in ensuring that the Company can continue to provide reliable service as APS transitions to a decarbonized generation fleet. These resources will remain in operation until clean generation is capable of providing the necessary capacity value and can ensure around-the-clock reliability. As this transition occurs, APS's customers will see benefits in terms of incremental Operations and Maintenance (O&M) cost savings, given that APS's clean resource investments involve operations that require significantly less O&M expense than traditional thermal resources. As APS retires older and less clean units, the Company can realize O&M cost savings which gives APS the opportunity to reallocate O&M budgets to ensure reliable performance of the rest of the APS non-renewable generation fleet. That fleet will be essential in meeting customer demand until technology advancements enable further clean generation deployments.

F. *Renewable Generation*

Q. WHAT CAPITAL EXPENDITURES ARE INCLUDED IN THE PROPOSED PTYP RELATED TO RENEWABLE GENERATION?

A. The Company requests a total of $539.6 million in renewable generation capital expenditures. This category includes the AZ Sun Battery Phase I project (shown in Figure 7) for $180.2 million, AZ Sun Battery Phase 2 for $118 million, and the Agave Solar Project for $241.5 million.

Figure 7: AZ Sun Battery Phase I Project



The first phase of the AZ Sun Battery project involves battery storage installations at seven APS solar facilities that provide a total of 141 megawatts (MW) of energy storage. These solar facilities will be retrofitted with battery storage systems to enable the delivery of clean, solar electricity during peak demand hours when customers need it most. Phase II includes a total of 60 MW of battery storage at two existing solar locations. These batteries are part of APS's summer readiness plan to deliver clean electricity to customers and serve peak demand during the hottest time of the year.

This project allows the Company to maximize the use of intermittent renewable generation by capturing excess output of solar generation during the day at these solar sites, and redeploying it on the grid after sunset, when the system is still experiencing peak demand and solar is no longer generating power. With a focus on customer affordability and enhanced reliability, this project provides unique

value by utilizing property the Company already owns and leveraging federal tax incentives for clean generation. The tax incentives APS plans to realize from this investment will lower the overall cost of the investment and are reflected as a reduction to PTYP.

The Agave Solar Project (Figure 8) is a 150 MW standalone photovoltaic (PV) solar project that will provide customers with clean, renewable generation. This project is energy storage ready and is anticipated to be paired with 400 MW of future batteries. The project takes advantage of existing infrastructure by leveraging previously owned Company land with close proximity to transmission infrastructure.

Figure 8: Agave Solar Project



VII. COAL COMMUNITY TRANSITION

Q. WHAT IS APS'S REQUEST RELATED TO COAL COMMUNITY TRANSITION?

A. APS is requesting to recover $106.5 million over nine years, approximately $16 million in the first year, through its Renewable Energy Adjustment Charge (REAC) to support Coal Community Transition (CCT) as a result of the early retirement of APS's coal-fired power plants. Four Corners Power Plant (located near Shiprock, New Mexico within the Navajo Nation) has a planned retirement in 2031, Cholla Power Plant (located near Joseph City, Arizona in Navajo County) is planned for retirement in 2025, and Navajo Generating Station (located near Page, Arizona and the Hopi Tribe reservation within the Navajo Nation) was retired in 2019.

The communities receiving CCT funding include the Navajo Nation, the communities surrounding the Cholla Power Plant in Navajo County, and the Hopi Tribe as detailed in APS witness Jessica Hobbick's testimony. This $106.5 million funding request represents the total CCT funding APS requested in its 2019 Rate Case less those CCT funds approved in Decision No. 78317 and would provide the following:

- $3.75 million for the Navajo Nation to support home and business electrification efforts;
- $10.4 million for the Navajo County communities in CCT financial support;
- $2.35 million for the Hopi Tribe in CCT financial support; and
- $90 million for the Navajo Nation in CCT financial support.

Q. WHY IS APS SEEKING THIS CCT FUNDING AS PART OF THIS RATE CASE?

A. While Decision No. 78317 approved only a portion of APS's full CCT proposal, it made clear that APS had the option of pursuing authorization for the remainder of

this funding in APS's next rate case. Since that decision was issued in November of 2021, APS has been fully participating within the Commission's generic CCT Docket[4] and expects that the work in that docket will be finalized before the end of 2022. For these reasons, APS is now renewing its request for the Commission to approve the remainder of the Company's CCT proposal ($106.5 million), which reflects the amount requested but not approved in the 2019 Rate Case. While evaluating this renewed request for CCT support funding, APS expects that the Commission will take into account the policy recommendations resulting from the generic CCT Docket.

Q. HAS APS ENTERED INTO ANY AGREEMENTS RELATED TO CCT?

A. Yes, based upon input from intervening parties in APS's 2019 Rate Case, APS and the Navajo Nation have entered into an agreement, dated August 6, 2021, regarding APS's commitment to provide CCT support for the Navajo Nation. This agreement is attached hereto as Attachment JT-07DR.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[4] Docket No. E-00000A-21-0010, In the Matter of Impact of the Closures of Fossil-Based Generation Plant on Impacted Communities.

CUSTOMER TECHNOLOGY INNOVATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
1	23rd Ave Microgrid	Customer-sited resource to provide a cleaner technology solution and allow APS to utilize grid benefits such as frequency response and capacity. Microgrid located at the 23rd Ave wastewater treatment plant (WWTP) with a capacity of 7.5MW standby/6.72 prime.	2023-Q1	$ 6,384,599	$ 961,629	$ 7,346,228
2	C&I Level 2 Charging	Provide Level 2 equipment and/or infrastructure for EV charging for workplace, fleet and multi-family.	Various	$ 2,809,455	$ 6,639,393	$ 9,448,848
3	**Total Customer Technology Innovation**			**$ 9,194,055**	**$ 7,601,022**	**$ 16,795,076**

NOTE: There may be variances in displayed values due to rounding.

INFORMATION TECHNOLOGY AND FACILITIES
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
1	Application Sustainability	Support and maintain application upgrades needed to ensure software is kept up to date.	Various	$ 10,631,816	$ 11,257,551	$ 21,889,367
2	Aragonne Wind Farm	Build and integrate systems to be able to dispatch existing and new Power Purchase Agreement facilities at Aragonne.	2022-Q3	$ 472,345	$ 21,683	$ 494,028
3	Client Applications	Ensures Windows workstation operating systems and back office applications are kept secure at a supported level while adding functionality to improve business productivity	Various	$ 122	$ 551,836	$ 551,957
4	Computer upgrades	Firewall Management Tool is for managing, securing and monitoring compliance of firewall rule policies which is required for Western Electricity Coordinating Council compliance	Various	$ 968,423	$ 3,691,999	$ 4,660,422
5	2021 Firewall Management Tool	The current WECC audit mitigation using a third-party tool to run reports on a periodic basis needs to be improved or replaced. This commitment was made to WECC as part of our response in the recent audit.	2022-Q3	$ 709,660	$ 126,739	$ 836,400
6	Identity Access Management System	Install Identity Access Management System to replace obsolete application and reduce cyber security risks.	2023-Q1	$ 4,735,817	$ 3,457,926	$ 8,193,743
7	Illuminate Advanced Apps - Phase 2 5	Implement the new phase of Advanced Distribution Management System with functionality for automated voltage control and fault isolation with recommended restoration.	2022-Q3	$ 15,051,040	$ 272,008	$ 15,323,048
8	Information Security & Compliance Obsolescence	The replacement of outdated, unsupported, and/or no longer effective systems. The purpose of the Security Program is to ensure the critical systems we rely on are functional, supported and operational.	Various	$ 448,303	$ 778,731	$ 1,227,034
9	Local Area Network	Replace end of line/non-scalable routers, decommission Corporate Security and Smart Grid firewalls.	Various	$ 4,231,144	$ 3,410,435	$ 7,641,579
10	MOD-30 IT TransOps Support 2020	Modify calculation method for Wholesale Market Electricity transmission availalbity from Point to Point scheduling (NERC MOD-029) to flow based scheduling (NERC MOD-030).	2022-Q4	$ 2,183,414	$ 191,565	$ 2,374,979
11	Monitoring Systems	Employ advanced monitoring systems to ensure reliable business operations and avoid IT system outages.	2022-Q3	$ 3,968,735	$ 28,844	$ 3,997,579
12	Variable Contract Pricing Tool	Enhance ability to settle variable priced contracts driven by the implementation of new energy storage Power Purchase Agreements.	2022-Q3	$ 1,068,241	$ 95,520	$ 1,163,761
13	Bill Redesign & System Enhancements	This will enhance Customer Care and Billing (CC&B), aps.com and associated integrations to provide new bill functionality.	2023-Q1	$ 1,377,735	$ 718,628	$ 2,096,363
14	Storage	Additional disks for organic data growth, memory & central processing unit (CPU) to improve performance, and manage and protect data	2022-Q4	$ -	$ 31,891	$ 31,891
15	Transmission and Distribution Communication Program 2022	Implement, replace, or upgrade communication infrastructure to support Advanced Grid Technology (AGT) Power Quality and Reliability Programs.	2022-Q4	$ 3,149,596	$ 1,904,114	$ 5,053,710
16	Total Outage Application (TOA) Enhancement	Update and enhance the TOA application and apply additional business critical functionalities to ensure outages on the electric grid are performed efficiently, safely, and correctly.	2022-Q3	$ 1,001,829	$ 36,643	$ 1,038,472
17	Wide Area Network	Provide increased bandwidth for statewide licensed microwave communications installations. Replacements for serial multiplexers and microwave radio and supporting power systems.	Various	$ 10,152,537	$ 6,340,980	$ 16,493,517

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INFORMATION TECHNOLOGY AND FACILITIES
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
18	Customer Contact Center Improvements - 2022	Enhancement project for prioritized improvements to the Interactive Voice Response (IVR)	2022-Q4	$ 259,792	$ 553,315	$ 813,107
19	Customer Care & Billing (CC&B) Enhancements 2022	Annual enhancement project for prioritized improvements to Customer Care & Billing (CC&B)	2022-Q4	$ 1,045,982	$ 234,039	$ 1,280,022
20	Field Area Network	Provide radio communications connectivity for system management, control, measurement and optimization.	2022-Q4	$ 200,045	$ 233,568	$ 433,613
21	License Renewal	Renewal of hardware and software licenses related to design, construction, backup server, enhanced aps.com search engine capabilities and customer experience management.	Various	$ -	$ 5,560,000	$ 5,560,000
22	Joint Use Solution	Create the ability to track easements, permits, expiration dates, and Rights of Way (ROW). Support Joint Use needs to manage contracts (contract management system, e.g. easements, ownership, payment terms, expiration dates).	2022-Q3	$ 137,334	$ 49,101	$ 186,435
23	Power Purchase Agreement -Westwing 1 Battery Energy Storage System (BESS)	Provide operators the ability to automatically dispatch the system, traders the ability to bid the system and all operations teams visibility to system status.	2022-Q4	$ -	$ 262,225	$ 262,225
24	Customer to Grid Solutions (C2GS) Software Support	Provide software support for C2GS business unit.	2022-Q4	$ -	$ 13,410	$ 13,410
25	Modern Learning Platform ELM replacement- 2022	Develop a Learning Management System and implement Agile Modern Training Platform to provide a multi-channel learning platform, enhance the ability to plan, manage and track training and effectiveness at an individual employee level.	2023-Q2	$ -	$ 2,642,211	$ 2,642,211
26	Day-Ahead Energy Imbalance Market (EIM) Process Improvement	Upgrade Energy Imbalance Market (EIM) Software to align with current standard and improve processes for Day Ahead and Real Time teams. Changes enhance functionality to allow faster modeling for multiple scenarios and enable better system vendor support.	2023-Q2	$ -	$ 489,750	$ 489,750
27	Enterprise PI Asset Framework and Analyses Server Upgrades	Enterprise PI Asset Framework and Analyses Server Upgrades	2023-Q2	$ -	$ 253,809	$ 253,809
28	Modernization Of Outage Notification (MOON)	Customer experience improvements related to outage notifications and data analytics to improve communications.	Various	$ 703,816	$ 649,155	$ 1,352,971
29	APS com Enhancements	Aps.com 2022 enhancement project for prioritized improvements	2022-Q4	$ 812,018	$ 1,727,282	$ 2,539,300
30	Data Analytics	Provide dynamic predictive risk and asset failure models to facilitate data driven decisions for maintenance, inspection, capital planning, and replacement.	Various	$ 8,998,589	$ 3,554,365	$ 12,552,954
31	ServiceNow - Disaster Recovery Program Management	Implement new ServiceNow module for managing Disaster Recovery (DR) Program including scheduling and tracking of activities and compliance.	2023-Q1	$ 1,045,614	$ 181,891	$ 1,227,505
32	Deer Valley - Protection Engineering Lab	Maintain reliable facilities to support business operations. The relocation will provide the adequate and efficient space needed for the business unit that the existing space is lacking.	2022-Q3	$ 784,010	$ 126,838	$ 910,848
33	Cottonwood Service Center	New Cottonwood Service Center to improve material handling operations, consolidate Verde Valley Supply Chain, IT Transportation, and Distribution operations into one location.	2023-Q2	$ 13,643,749	$ 13,858,372	$ 27,502,121
34	HUBwest - Western Service Center Infrastructure, Building and Central Stores Hub	Create a safer, more efficient workplace for employees by improving material handling and storage and consolidating undersized and aging buildings. Consolidate existing facilities into HUBwest location which will increase warehousing and garage and service capabilities.	2023-Q1	$ 95,491,478	$ 33,158,930	$ 128,650,409

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INFORMATION TECHNOLOGY AND FACILITIES
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
35	Yucca East Warehouse	New building to replace infrastructure at the end of its useful life an provides necessary space to properly store materials while improving site efficiency and safety. This project consolidates access to parts and equipment currently dispersed across the site.	2023-Q1	$ 4,108,527	$ 1,052,750	$ 5,161,276
36	Four Corners Machine Shop HVAC Installation	The purpose of this project it to provide heating/cooling to the building.	2022-Q4	$ 12,868	$ 477,871	$ 490,739
37	Corporate Modifications	Support modification and renovation projects to reconfigure and remodel of work spaces to accommodate business needs.	Various	$ 43,229	$ 928,276	$ 971,506
38	Facilities Run Maintain-Building	Planned predictive replacements of foundations, walls, roofs, ceilings, stairs, floor coverings, windows, plumbing and fixtures, built-ins, office lighting, conventional doors and partitions, decorations, and modular trailer buildings	Various	$ 251,432	$ 2,373,937	$ 2,625,369
39	Facilities Run Maintain-HVAC	Planned predictive replacements of HVAC (heating, ventilation, and air conditioning) equipment/components	Various	$ 35,369	$ 421,411	$ 456,780
40	Deer Valley Workplace of the Future Implementation	Maintain reliable facilities to support business operations. The remodel of Deer Valley Building A to create efficient space that aligns with a more flexible workforce.	2022-Q4	$ 1,664,636	$ 1,606,901	$ 3,271,537
41	Four Corners Unit 4 HVAC Replacement	New cooling unit for Four Corners Unit 4 Breaker Room to provide a reliable HVAC for plant controls equipment and personnel. The HVAC systems are approaching the end of their serviceable life and require replacement.	2022-Q4	$ 6,865	$ 201,693	$ 208,558
42	Deer Valley - Distribution Operations Center Expansion	Maintain reliable facilities to support business operations. Business unit has inadequate number of operator stations. This project will increase the operator seat count.	2022-Q4	$ 51,816	$ 399,850	$ 451,666
43	Electric Vehicle (EV) Charging	Provide adequate Electric Vehicle (EV) charging infrastructure for all employees onsite statewide.	Various	$ 104,448	$ 388,727	$ 493,175
44	Fleet Electric Vehicle (EV) Charging	Maintain reliable facilities to support business operations. Provide adequate Electric Vehicle (EV) charging infrastructure for all fleet vehicles statewide.	2022-Q3	$ 397,670	$ 141,686	$ 539,356
45	Ocotillo Dock Expansion	Maintain reliable facilities to support business operations. Concrete extension as the current loading dock does not meet requirements for loading/unloading materials safely for the plant.	2022-Q4	$ -	$ 517,734	$ 517,734
46	Transportation Shop Equipment	Capital equipment needed to maintain safe operation of the APS vehicle fleet	2023-Q1	$ -	$ 179,434	$ 179,434
47	Equipment from Lease Buyouts, net of Vehicle Retirement and Sale	Purchase of APS vehicles at the end of their lease term, net of sales of APS vehicles no longer in service.	Various	$ 133,398	$ 2,256,432	$ 2,389,831
48	**Total Information Technology and Facilities**			**$ 190,083,442**	**$ 107,412,057**	**$ 297,495,498**

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NUCLEAR GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
1	Vehicle Replacements 2022	Replace a number of aging vehicles to ensure that the site's vehicle fleet is safe and reliable, with minimal maintenance.	2022-Q3	$ 48,637	$ 37,772	$ 86,408
2	Spray Pond Concrete Replacement Unit 2	Replacement of degraded concrete components of the spray pond structures. The spray ponds are approximately 30 years old with cracks in the concrete requiring replacement to ensure long-term safe operation.	2022-Q4	$ 2,339,585	$ 1,061,071	$ 3,400,656
3	Spray Pond Concrete Replacement Unit 3	Replacement of degraded concrete components of the spray pond structures. The spray ponds are approximately 30 years old with cracks in the concrete requiring replacement to ensure long-term safe operation.	2022-Q4	$ 4,988,213	$ 484,974	$ 5,473,187
4	Spray Pond Chemical Addition	Improve the usability and safety of the spray pond injection system. The chemical skid, pipes, and tanks will be replaced with alloy materials which will ensure system reliability and leak prevention.	2022-Q4	$ 1,626,173	$ 225,818	$ 1,851,991
5	Digital Strategic Modernization Program (SMP) Phase 1	The SMP will replace several plant control systems, both analog and digital, with newly designed and upgraded equipment. The intention of this upgrade is to address obsolescence, remove single point vulnerabilities where practical, improve Human-Machine Interfaces, and minimize spare part inventories.	2022-Q4	$ 1,717,064	$ 330,929	$ 2,047,993
6	Spray Pond Concrete Replacement Unit 1	Replacement of degraded concrete components of the spray pond structures. The spray ponds are approximately 30 years old with cracks in the concrete requiring replacement to ensure long-term safe operation.	2022-Q4	$ 2,769,593	$ 1,185,401	$ 3,954,994
7	Hydrazine Vacuum Drag Package	The hydrazine vacuum package will provide a new additional method of injecting hydrazine into the condensate system.	2022-Q4	$ 282,548	$ 17,162	$ 299,710
8	Normal Chiller Replacement Unit 1	This project will replace all small Normal Chillers with a "Chiller Farm." Current Chillers are obsolete and no longer supported by the vendor.	Various	$ 2,208,214	$ 210,142	$ 2,418,355
9	Liquid Storage Nitrogen Tank Replacement	This project will replace the liquid storage nitrogen tanks in all three units.	2022-Q4	$ 28,422	$ 1,779	$ 30,201
10	Domestic Water System Piping Replacement	Install the pressure relief valves and/or a surge tank, to minimize the potential for leakage failures.	2023-Q2	$ 110,890	$ 140,480	$ 251,370
11	Cathodic Protection 2019	On-going replacement of failed anodes and support devices, which has been the basis of the Cathodic Protection Replacement Program since its inception.	2022-Q3	$ 365,549	$ 7,612	$ 373,162
12	Control Element Drive Mechanism (CEDM) Coil Stack	The scope of this project is to replace CEDM Coil Stacks with high temperature coil stacks.	2022-Q4	$ 45,927	$ 2,277,511	$ 2,323,438
13	Fatigue Software Upgrade	Replace the current fatigue management software with an updated version to receive and benefit from vendor enhancements and additional functionalities.	2023-Q1	$ 82,840	$ 107,816	$ 190,656
14	Diesel Building Crane Pendant	Replace the diesel building crane pendant with a remote pendant system.	Various	$ 165,800	$ 126,990	$ 292,790
15	Control Valve Digital Positioners-Unit 3	Replace existing analog and pneumatic valve positioners with new Fisher Digital Valve Controller Modules, to provide accurate valve positioning, as well as significant reduction in hysteresis and maintenance costs.	2022-Q4	$ 6,815	$ 71,033	$ 77,848
16	Emergency Diesel Generator Protective Relay Replacement 3A	Replace the under-frequency relay with a microprocessor-based master all-in-one generator protective relay unit, resulting in significant cost savings from reduced maintenance.	2023-Q1	$ 239	$ 91,032	$ 91,271
17	Water Resources Concentrate Treatment System	Conceptualize and design a Concentrate Treatment System	2023-Q1	$ 64,457	$ 10,738	$ 75,195

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NUCLEAR GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
18	Water Resource Facility Clarifier Life Extension T4	Inspect, and replace degraded or outdated clarifier components, and concrete to extend the Clarifier's useful life for an additional 30 years.	2023-Q1	$ 5,306,035	$ 2,002,284	$ 7,308,319
19	Balance of Plant Engineered Safety Features Actuation System Cabinet Replacement Unit 2	Reverse engineer and replace all modules in the existing Balance of Plant Engineered Safety Features Actuation System with current components and techniques.	2023-Q2	$ 855	$ 186,722	$ 187,577
20	Plant Data Application Replacement	Improvements within the System Engineering toolset to align with industry standards.	2022-Q3	$ 175,768	$ 12,479	$ 188,247
21	Efficiency Remodel Outage Support Building Unit 2	The scope of this project is to group several office spaces within the Unit 2 outage support building.	2022-Q3	$ 170,438	$ 201,468	$ 371,906
22	Palo Verde Project Management Offer Software Enhancements	Project Management Office software replacement to better manage and control projects.	2022-Q3	$ 71,214	$ 5,291	$ 76,506
23	Thermoluminescent Dosimeters System Upgrade	Replace the obsolete Panasonic UD-710 readers and associated UD-809 and UD-812 dosimeters with a current state-of-the-art dosimetry system, which is used widely throughout the nuclear industry. This will enable Palo Verde to continue to process dosimeters on-site.	2022-Q3	$ 492,920	$ 36,753	$ 529,674
24	Water Resources Hassayampa Pumps Project	This project will replace several pumps at the Hassayampa pumping station.	2022-Q4	$ 396,532	$ 30,654	$ 427,186
25	Clarifier 13 Turbine Gear Replacement	Install Clarifier 13 main split gear and replace gear box internals (seals, pinion gear, bull gear and associated bearings) with new equipment.	2022-Q4	$ 246	$ 96,969	$ 97,215
26	Strategic Modernization Program (SMP) Phase II	The Strategic Modernization Program (SMP) will replace several plant control systems, both analog and digital with newly designed and upgraded equipment. This upgrade is to address obsolescence, remove single point vulnerabilities where practical, improve Human-Machine interfaces, and minimize spare part inventories.	2023-Q1	$ 6,374,323	$ 7,434,683	$ 13,809,006
27	Low Pressure Feedwater Heater Replacement	This project is to replace the low pressure feed water heaters, which are nearing the end of their useful life.	2023-Q2	$ 601,062	$ 3,965,257	$ 4,566,319
28	Core Network Data Center Infrastructure	This project is to upgrade the core network with a supported and up to date infrastructure. This effort also will replace and improve the Data Center access layer, addressing support and security.	2022-Q3	$ 157,806	$ 3,714	$ 161,520
29	Data Validation And Reconciliation	Data Validation & Reconciliation (DVR) is a plant monitoring tool that enables identification of generation losses, equipment degradation, and instrument calibration issues. The software will help Palo Verde reduce calibration maintenance, recover generations losses, early identification of degradation of equipment.	2022-Q3	$ 113,262	$ 10,141	$ 123,403
30	Warehouse Fire Protection Replacement	Replace degraded fire sprinkler and fire suppression systems.	2022-Q3	$ 287,851	$ 155,961	$ 443,812
31	Turbine Building Elevator Replacement Unit 1	Replace of worn Unit 1 Turbine Building elevator cars and components.	2022-Q4	$ 138,180	$ 126,530	$ 264,711
32	QlikView Replacement	QlikView is currently used to develop reports and will be replaced and integrated with new reporting tools.	2022-Q4	$ 190,070	$ 72,608	$ 262,678
33	E-Field Obsolescence Replacement	The Security E-Field Detection System will be upgraded to resolve hardware end of life obsolescence issues.	2023-Q1	$ 29,682	$ 114,135	$ 143,817
34	Motor Replacements Unit 1 2022	Replacement of motors to prevent unplanned outages.	2022-Q4	$ 128,446	$ 9,292	$ 137,738

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NUCLEAR GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
35	Pump Replacement Unit 1 2022	Replacement of valves to protect plant equipment and increase equipment availability.	2022-Q4	$ 213,539	$ 14,960	$ 228,498
36	Valve Replacements Unit 1 2022	Replacement of valves to protect plant equipment and increase equipment availability.	2022-Q4	$ 297,092	$ 20,997	$ 318,089
37	Concrete And Paving 2022	The scope of this project is to replace worn out paving, concrete, and asphalt roadways and sidewalks around the site.	2022-Q4	$ 26,113	$ 217,036	$ 243,149
38	Cathodic Protection 2022	Replacement of failed anodes and support devices employed in the Cathodic Protection System.	2022-Q4	$ 68,274	$ 121,104	$ 189,378
39	Small Scale Facilities Projects 2023	Facilities modernization and refurbishment projects that individually cost less than $100k within the common area.	2022-Q4	$ 51,748	$ 39,254	$ 91,002
40	HVAC Replacements 2022	Replace failed and failing HVAC units across the site to keep work areas habitable.	2022-Q4	$ 37,498	$ 2,770	$ 40,268
41	Cooling Tower Life Extension 2022 Unit 3	The scope of this project is replacement of structural components in the cooling towers to improve their operational efficiency, structural integrity, and extend their lives.	2022-Q4	$ 23,263	$ 3,063,220	$ 3,086,483
42	Site Tools And Equipment 2022	Replace old tools and equipment that are unreliable and obsolete with improved and safer models of tools.	2022-Q4	$ 47,707	$ 68,369	$ 116,075
43	Valve Replacements Unit 3 2022	Replacement of valves to protect plant equipment and increase equipment availability.	2022-Q4	$ 24,300	$ 605,829	$ 630,129
44	Emergency Support Function (ESF) Transformer Replacement Unit 4	This project will replace the ESF transformers which are the preferred power source for class 1E busses supplied from the Start-Up Transformers or through 13.8 kV switchgear through the ESF Transformers.	2022-Q4	$ 15,722	$ 403,803	$ 419,525
45	Auxiliary Transformer Unit 3	This project will replace the unit auxiliary transformer, which converts the 24kV to 13 8kV and provides power to both 13.8 kV non-class buses using dual secondary winding system.	2022-Q4	$ 965,135	$ 713,124	$ 1,678,259
46	Palo Verde Information Tech Equip Replacement 2022	This project will replace technology equipment and tools used for various operational and maintenance needs at Palo Verde Generating Station.	2022-Q4	$ 44,730	$ 61,619	$ 106,349
47	Life Cycle Computer Replacement 2022	Replace outdated desktop networked computer workstations.	2022-Q4	$ 43,544	$ 15,451	$ 58,994
48	Circuit Breaker Replacement Unit 3 2022	Replace and rebuild circuit breakers to maintain and protect plant equipment and increase equipment availability.	2022-Q4	$ 12,098	$ 60,690	$ 72,788
49	Circuit Breaker Replacement Unit 2 2022	Replace and rebuild circuit breakers to maintain and protect plant equipment and increase equipment availability.	2022-Q4	$ 119,691	$ 9,195	$ 128,886
50	Water Resources Site Tools & Equipment 2022	Purchase and replacement of site tools and equipment used throughout the site for repair work, and testing.	2022-Q4	$ 25,143	$ 30,637	$ 55,780
51	Water Resources Breaker Rebuilds Spring 2022	Rebuild various circuit breakers at Water Resources are used to power load centers which run the equipment (such as pumps and motors) used in support of water production. All of these breakers are on a Preventative Maintenance (PM) program for rebuild to assure that they remain in good working condition.	2022-Q3	$ 16,292	$ 407	$ 16,699

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NUCLEAR GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
52	Small Scale Water Resources Projects 2023	To maintain continuous operation at Palo Verde Water Resources, there are a number of small projects that go on throughout the year. Examples of this includes expansion joint replacements, or cathodic protection anode bed replacements.	2022-Q4	$ 130,969	$ 34,382	$ 165,350
53	Instrumentation and Controls (I&C) And Electrical Unit 1 2022 Online	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc.	2022-Q4	$ 53,591	$ 68,974	$ 122,565
54	Instrumentation and Controls (I&C) And Electrical Unit 2 2022 Online	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc.	2022-Q4	$ (13,418)	$ 72,642	$ 59,223
55	Instrumentation and Controls (I&C) And Electrical Unit 3 2022 Online	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc.	2022-Q4	$ 17,769	$ 73,944	$ 91,713
56	Instrumentation and Controls (I&C) And Electrical Unit 3 2022 Outage	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc.	2022-Q4	$ 849	$ 241,121	$ 241,970
57	Valve Replacements Unit 2 2022	Replacement of valves to protect plant equipment and increase equipment availability.	2022-Q4	$ 24,974	$ 129,701	$ 154,675
58	Digital Strategic Modernization Program Phase II Simulator A	The Strategic Modernization Program (SMP) will replace several plant control systems, both analog and digital with newly designed and upgraded equipment to address obsolescence, remove single point vulnerabilities where practical, improve Human-Machines interfaces, and minimize spare part inventories.	2022-Q4	$ 429,964	$ 47,202	$ 477,166
59	Turbine Building, Elevator Replacement Unit 3	Replace degraded Unit 2 Turbine Building elevator cars and components to ensure safe operation.	2022-Q3	$ 151,045	$ 55,633	$ 206,678
60	X-Ray Machine Replacement	The scope of this project will be to replace seven personnel search X-rays machines in order to resolve end of life obsolescence issues associated with hardware and software.	2022-Q4	$ (1,809)	$ 26,540	$ 24,731
61	Small Scale Materials Projects 2022 Unit 1	Replace qualifying small scale projects, such as expansion joint replacements within pipe, or cable replacements.	Various	$ 23,873	$ 10,825	$ 34,698
62	Small Scale Materials Projects 2022 Unit 2	Replace qualifying small scale projects, such as expansion joint replacements within pipe, or cable replacements.	2022-Q4	$ 16,608	$ 5,637	$ 22,245
63	Small Scale Materials Projects 2022 Unit 3	Replace qualifying small scale projects, such as expansion joint replacements within pipe, or cable replacements.	2022-Q4	$ 115,218	$ 17,508	$ 132,726
64	Electric Work Packages Software Enhancements	Enhance Electric Work Packages (eWP) software functionality based on worker feedback and optimizing work process priorities.	2022-Q4	$ 85,535	$ 88,514	$ 174,049
65	PipeStress Software Replacement	Purchase and implement the PipeStress application at Palo Verde. Support data conversion from ME101 to PipeStress, and utilize the vendors software qualification program to satisfy the 10 CFR 50.59 requirements.	2022-Q3	$ -	$ 28,142	$ 28,142
66	Diesel Generator Fire Rated Roll Up Door Replacement - Unit 1	Replace the fire rated door in the Unit 1 Diesel Generator building.	2022-Q3	$ -	$ 8,951	$ 8,951
67	Chemistry Lab and Test Equip 2022	Replacement of aging or obsolete Chemistry laboratory and instrumentation to maintain sampling availability and effectiveness.	2022-Q3	$ -	$ 12,532	$ 12,532
68	Information Technology Software Tools 2021	Project will replace technology equipment and tools used for various operational and maintenance needs at Palo Verde.	2022-Q4	$ -	$ 16,371	$ 16,371

NOTE: There may be variances in displayed values due to rounding.

NUCLEAR GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
69	Filer Upgrades 2022	Project will replace technology equipment and tools used for various operational and maintenance needs at Palo Verde.	2022-Q4	$ -	$ 27,823	$ 27,823
70	Fixed In-Core Detectors Unit 3 2022	Replacement of Fixed In-core Detectors inside the Reactor Vessel.	2022-Q4	$ -	$ 687,360	$ 687,360
71	Computer Network Infrastructure 2022	Lifecycle management for Network Infrastructure in 2022.	2022-Q4	$ -	$ 52,773	$ 52,773
72	Station Battery Replacement Unit 2 2022	Maintain critical batteries for safe shutdown of the reactor in the event of a station blackout.	2022-Q4	$ -	$ 30,206	$ 30,206
73	Water Resources Instrumentation and Controls Equipment Replacement 2023	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the Water Resources Facility.	2022-Q4	$ -	$ 35,166	$ 35,166
74	Water Resources Valve Replacement 2022	Replacements of valves and valve internals due to degradation or failure.	2022-Q4	$ -	$ 25,583	$ 25,583
75	Water Resources Cathodic Protection 2022	Water Reclamation Supply System (WRSS) pipeline anode/rectifier replacement	2022-Q4	$ -	$ 61,149	$ 61,149
76	Motor Replacements Unit 2 2022	Replacement of motors to prevent unplanned outages.	2022-Q4	$ -	$ 9,062	$ 9,062
77	Ovation Data Diode Installation	Ovation Network is a system used to digitally control equipment in the Water Resources Facility (WRF). This project will install data diode to allow for flow of data from Ovation Network to equipment in the WRF.	2022-Q4	$ -	$ 90,802	$ 90,802
78	Circulating Water Pump Pit Unit 3 2022	This project will replace degraded concrete in circulating water pump pit.	2023-Q1	$ -	$ 335,088	$ 335,088
79	Trailing costs for projects in service prior to June 30, 2022	Includes multiple projects that went into service prior to June 30, 2022 but have trailing charges that extend into the Post Test Year period.		$ 257,026		$ 257,026
80	**Total Nuclear Generation**			**$ 34,809,739**	**$ 28,595,295**	**$ 63,405,034**

NOTE: There may be variances in displayed values due to rounding.

DISTRIBUTION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
1	Shea: Feeder #6 Build Underground Line	Improve reliability by creating an underground tie to adjacent substation.	2023-Q2	$ 46,888	$ 2,765,757	$ 2,812,645
2	Network Protectors	Replace end-of-life network equipment that provides redundant feeds to critical customers such as hospitals.	Various	$ 14,901,639	$ 8,276,608	$ 23,178,247
3	Aged Conductor Replacement	Install modern protection devices to protect legacy small wire from damage/burning down during fault conditions and reconductor small wire and backbone sections where necessary.	Various	$ 1,025,588	$ 2,843,328	$ 3,868,916
4	Advanced Grid Technology (AGT) Power Quality	Improve feeder reliability by installing automated devices (supervisory capacitor banks, voltage regulators, and micatu sensors) to support operations and control processes.	Various	$ 4,024,950	$ 2,410,748	$ 6,435,699
5	Advanced Metering Infrastructure (AMI) Communication Infrastructure	Replace metering devices that use deprecated 2G/3G cellular networks or proprietary mesh networks which are expected to become unavailable/insufficient for business function over time. Enhance metering capabilities for initiatives such as voltage polling and outage notification.	Various	$ 273,467	$ 1,729,645	$ 2,003,112
6	Capital Advanced Metering Infrastructure (AMI) Meters	Purchase various AMI meters in support of AMI meter installation, replacement and specialized metering programs (renewables, etc.).	Various	$ -	$ 10,042,018	$ 10,042,018
7	Fire Mitigation	Proactively inspect and manage assets to prevent potential fire hazards throughout the system.	Various	$ 857,654	$ 7,556,775	$ 8,414,429
8	Overhead Planned Replacements	Replace damaged, defective or failed equipment needing replacement as noted during annual Distribution Line Patrols.	Various	$ 7,154,126	$ 6,190,402	$ 13,344,528
9	Oil Switch Replacement	Remove and replace aged switch infrastructure that presents a significant safety risk to operators.	Various	$ 369,723	$ 686,762	$ 1,056,485
10	Highway Relocation-Distribution	To comply with requirements driven by governmental agencies.	Various	$ 5,793,303	$ 9,241,389	$ 15,034,693
11	Wood Pole Replacements	Replace poles with less than 10 years of remaining life to reduce distribution outages due to downed distribution poles and mitigate public hazards.	Various	$ 408,969	$ 5,393,604	$ 5,802,573
12	Service Replacements	Install service/secondary cable in conduit so that moisture and rocks will not damage the cables.	Various	$ 244,891	$ 4,060,804	$ 4,305,695
13	Storm Restoration - Lines	Restore distribution system equipment damaged during storms.	Various	$ 104,689	$ 4,650,692	$ 4,755,381
14	Streetlights and Dusk to Dawn	Provide streetlight and dusk to dawn services to customers.	Various	$ 370,988	$ 4,268,983	$ 4,639,971
15	Substation Aged Equipment Replacements	Replace aged, end-of-life assets to ensure a reliable system.	Various	$ 1,943,618	$ 1,361,954	$ 3,305,572
16	Substation Facilities Improvements	Improve substation facilities by replacing chainlink fencing with block walls, paving a drive way entrance for dust control, and landscaping.	Various	$ 391,383	$ 424,988	$ 816,371
17	Training Yard Capital Replacements	Training yard pole replacements.	Various	$ 721,738	$ 41,470	$ 763,207

NOTE: There may be variances in displayed values due to rounding.

DISTRIBUTION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
18	Underground Cabinet Replacement	Replace switching cabinets with broken latches or holes to reduce safety hazards.	Various	$ 424,076	$ 2,187,533	$ 2,611,609
19	Underground Cable Replacement-Planned	Install underground cable in conduit so that moisture and rocks will not damage the cables.	Various	$ 2,647,686	$ 5,495,712	$ 8,143,397
20	Underground Cable Replacement-Unplanned	Replace direct buried cable with cable in a conduit system to reduce power outages.	Various	$ 2,367,605	$ 14,288,763	$ 16,656,368
21	Underground Transformer Replacement	Replace damaged transformers to eliminate environmental and safety hazards.	Various	$ 988,936	$ 5,550,293	$ 6,539,229
22	Unplanned Emergency	Maintain and/or restore distribution system operations.	Various	$ 7,199,789	$ 18,118,559	$ 25,318,348
23	Capitalized Tools	Provide tools for field employees in order to work efficiently and safely.	Various	$ 348,872	$ 426,192	$ 775,064
24	Distribution Land Right-of-Way Renewals	Renew contractual agreements to Distribution rights-of-way leases that are due to expire.	Various	$ -	$ 637,982	$ 637,982
25	Capital Non-AMI Meters	Maintain Non-AMI meter inventory.	Various	$ -	$ 425,828	$ 425,828
26	McDowell Relay Upgrades	Install new substation relays to provide adequate protection to respond to system faults.	2022-Q4	$ 407,489	$ 362,569	$ 770,058
27	Buffalo Feeder #02 Upgrade Bottleneck	Increase feeder rating from 10.1MVA to 13 MVA to prevent overloading.	2023-Q1	$ 11,353	$ 160,493	$ 171,846
28	Buffalo Feeder #05 Upgrade Bottleneck	Increase feeder rating from 11.1MVA to 13 MVA to prevent overloading.	2023-Q1	$ 182,763	$ 925,426	$ 1,108,189
29	Extend Jackson Street Feeder #10	Improve reliability through installation of redundant feed.	2022-Q3	$ 46,217	$ 1,045,912	$ 1,092,129
30	2020 Supervisory Controlled Switch Installations	Improve feeder reliability by installing automated devices to support operations and control processes.	2022-Q4	$ 2,059,197	$ 126,397	$ 2,185,595
31	Aged Relay Replacement	Replacement of electromechanical relays past their useful life.	Various	$ -	$ 157,600	$ 157,600
32	Thornton 69kV Cap Bank Substation Work	Install capacitor banks at Thornton substation to ensure adequate voltage quality.	2023-Q2	$ -	$ 1,624,895	$ 1,624,895
33	System Hardening	Infrastructure improvements designed to bolster system robustness in at risk areas, including but not limited to fire risk.	Various	$ -	$ 1,313,337	$ 1,313,337
34	Evans Churchill Substation	Install 69kV Gas Insulated Switchgear (GIS), substation transformers, capacitor banks and control equipment to improve capacity, reduce safety hazards and improve reliability.	2023-Q2	$ 36,765,556	$ 13,768,858	$ 50,534,413

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DISTRIBUTION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
35	Advanced Grid Technology (AGT) Reliability	Improve feeder reliability by installing automated devices (supervisory reclosers and communicating trip savers) to support operations, fire mitigation, and control processes.	Various	$ 6,392,308	$ 5,946,840	$ 12,339,148
36	Tempe Substation: New Supervisory Cabinet	The purpose of this additional feeder is to move, manage and balance load and to reduce the risk of overloading a singular feeder.	2022-Q4	$ 589,898	$ 317,892	$ 907,790
37	Engineering Access Improvements - Farmer, Waldrip, Bell, Baja (2022)	Install communication equipment at Farmer, Waldrip, Bell, and Baja substations to provide remote engineering access to ensure safe operations and to improve response times.	2022-Q4	$ 25,747	$ 198,810	$ 224,557
38	Preacher Canyon Microgrid	Install Micro grid solution with 2.5MW diesel generators to improve feeder reliability.	2022-Q4	$ 3,858,203	$ 979,650	$ 4,837,854
39	Trailing costs for projects in service prior to June 30, 2022	Includes multiple projects that went into service prior to June 30, 2022 but have trailing charges that extend into the Post Test Year period.	Various	$ 1,701,075		$ 1,701,075
40	**Total Distribution**			**$ 104,650,384**	**$ 146,005,467**	**$ 250,655,851**

NOTE: There may be variances in displayed values due to rounding.

OTHER GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
1	Air Compressors	Ensure the timely replacement of air compressors in the fossil generation fleet to ensure unit reliability.	2022-Q4	$ 2,297,489	$ 1,126,637	$ 3,424,126
2	Batteries/Chargers/UPS	Execute scheduled and emergent batteries/chargers/UPS replacement projects across the fossil fleet.	2022-Q3	$ 1,898	$ 67,110	$ 69,009
3	Catalyst	Execute both scheduled and emergent catalyst replacement projects across the fossil fleet.	Various	$ 635,389	$ 6,949,870	$ 7,585,258
4	Cholla Unit 1 - 2023 Clinker Grinder Replacement	The purpose of this project is to maintain Cholla Unit 1 reliability as the clinker grinder will have reached the end of its useful life.	Various	$ -	$ 66,647	$ 66,647
5	Cholla Unit 3 - 2023 Clinker Grinder Replacement	The purpose of this project is to maintain Cholla Unit 3 reliability as the clinker grinder will have reached the end of its useful life.	Various	$ -	$ 133,294	$ 133,294
6	Cholla - Control Room Fire Panel Replacement	The purpose of this project is to maintain safe operation of the plant to protect personnel and equipment by replacement of obsolete equipment no longer supported by the vendor.	2022-Q4	$ 4,777	$ 87,545	$ 92,322
7	Cholla - Fly Ash Pond Dewatering	Facilitate successful completion of the Fly Ash Pond Closure project by late 2028.	2023-Q1	$ 294,983	$ 921,785	$ 1,216,768
8	Cholla - Mill Grinding Zone and Gear Drive Replacements 2022	Maintain unit reliability through installation of new mill components and gear drive components as failures or immediate need occurs throughout the 2022 calendar year.	2022-Q4	$ 1,711,107	$ 126,446	$ 1,837,553
9	Coal Handling	Maintain unit reliability by executing scheduled and emergent coal handling and pulverizer equipment replacement and upgrades.	2022-Q4	$ 285,669	$ 234,133	$ 519,802
10	Electrical Systems	Execute both scheduled and emergent breaker replacement projects across the fossil fleet.	Various	$ 2,915,725	$ 10,392,312	$ 13,308,037
11	Expansion Joints	Execute both scheduled and emergent expansion joint replacement projects across the fossil fleet.	2023-Q1	$ 592	$ 348,087	$ 348,679
12	Filters	Execute both scheduled and emergent fabric filter bag replacement projects across the fossil fleet.	Various	$ 659,296	$ 2,876,919	$ 3,536,216
13	Four Corners - Boiler Roof Tie Bar Replacement	The purpose of this project is to maintain unit reliability while reducing the risk of forced outages by replacing the damaged roof tie bar.	2023-Q2	$ -	$ 1,104,157	$ 1,104,157
14	Four Corners - Bottom Ash Clinker Grinder Replacement	The purpose of this project is to maintain unit reliability by replacing the bottom ash clinker grinders. The existing clinker grinders are approaching the end of serviceable life. This project will assure the consistent and reliable removal of bottom ash from the boiler.	2023-Q2	$ -	$ 131,145	$ 131,145

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OTHER GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
15	Four Corners - Coal Combustion Residuals (CCR) Groundwater Mitigation	The purpose of this project is to comply with federal coal combustion residuals (CCR) disposal regulations (40 CFR Part 257). The first round of groundwater sampling at the two CCR Units has shown a potential exceedance in fluoride. Additional rounds of sampling and testing, followed by statistical evaluation of all the collected data is required to determine if groundwater mitigation is necessary.	2023-Q1	$ 1,233,667	$ 367,466	$ 1,601,133
16	Four Corners - Confined Space/High Angle/Low Angle Rescue Equipment	This is Personal Protective Equipment (PPE) required for a fully functional confined space rescue team. Components are required to meet regulations including sets designated for use in an event and during training. OSHA 1926.1211 requires rescue teams must be properly equipped for, and proficient in, performing needed rescue services.	2022-Q3	$ 24,218	$ 11,185	$ 35,403
17	Four Corners - Dust Suppression Tank Installation	The purpose of this project is to maintain environmental compliance with coal combustion residuals (CCR) regulations by recycling water captured onsite to use for dust suppression and thereby reducing the amount of influent flow to the Return Water Pond.	2022-Q3	$ -	$ 164,671	$ 164,671
18	Four Corners - Effluent Limitation Guidelines (ELG) Plant Modifications	Maintain compliance with 2023 Effluent Limitation Guidelines (ELG) Bottom Ash regulations as defined by 40 CFR 423, by converting the existing plant wastewater and low volume wastewater systems to a closed loop configuration.	2023-Q2	$ 8,264,768	$ 28,431,998	$ 36,696,767
19	Four Corners - Fire Warning Detection System Replacement - Phase 2	The purpose of this project is to maintain safe operation of the plant and to protect personnel and equipment. The existing fire detection system, fire detection server and interconnecting control cable has reached the end of its serviceable life.	2022-Q3	$ 1,296,019	$ 107,696	$ 1,403,715
20	Four Corners - Local Area Network (LAN) Infoblox Replacement	The purpose of this project is to maintain reliability of network communication by replacing Internet Protocol (IP) Address Management appliances because they are obsolete, have reached the end of serviceable life.	2023-Q2	$ -	$ 27,647	$ 27,647
21	Four Corners Unit 4 - Lime Storage Tank Agitator and Gearbox Replacement	The purpose of this project is to maintain reliability for Four Corners Unit 4 of the Lime Slurry Feed System to ensure continued operation of the unit. Inspection of the components revealed degradation of the equipment and the agitator is nearing the end of serviceable life.	2022-Q4	$ 340,185	$ 224,012	$ 564,197
22	Four Corners Unit 5 - Lime Storage Tank Agitator Gearbox Replacement	The purpose of this project is to maintain reliability for Four Corners Unit 5 of the Lime Slurry Feed System to ensure continued operation of the unit. Inspection of the components revealed degradation of the equipment and the agitator is nearing the end of serviceable life.	2023-Q2	$ 184,334	$ 191,456	$ 375,790
23	Four Corners Unit 4 - Miscellaneous Lagging & Insulation Replacement - 2022	The purpose of this project is to maintain a safe plant work environment for Four Corners Unit 4 by eliminating potential hazards. These replacements are intended to reduce the hazards that exist when lagging and insulation are loose or deteriorating and therefore not maintaining surface temperature requirements, creating potential unsafe conditions for plant personnel and equipment.	2022-Q4	$ 108,056	$ 84,419	$ 192,475
24	Four Corners Unit 5 - Miscellaneous Lagging and Insulation Replacement - 2022	The purpose of this project is to maintain a safe plant work environment for Four Corners Unit 5 by eliminating potential hazards. These replacements are intended to reduce the hazards that exist when lagging and insulation are loose or deteriorating and therefore not maintaining surface temperature requirements, creating potential unsafe conditions for plant personnel and equipment.	2022-Q4	$ 101,505	$ 91,095	$ 192,600
25	Four Corners - North & South Train Lime Weigh Belt Feeders Replacement	The purpose of this project is to maintain unit reliability. The lime weigh belt feeders air approaching the end of their serviceable life and require replacement. Replacement parts are obsolete.	2023-Q2	$ 343,228	$ 687,021	$ 1,030,249
26	Four Corners - North Area Sump Replacement	The purpose of this project is to ensure compliance with Effluent Limitation Guidelines (40 CFR Part 243) while maintaining reliability of the sump. Existing pumps are at end of serviceable life, and an unpermitted or unregulated discharge of the sump could result in a Reportable Environmental Incident.	2022-Q4	$ 1,122,887	$ 480,672	$ 1,603,559
27	Four Corners - Oxygen Injection System Replacement	The purpose of this project is to maintain unit reliability. An automated and dependable oxygen injection system is required to prevent Flow Accelerated Corrosion (FAC) damage to boiler tubes and feedwater piping and equipment. The oxygen forms a protective layer over base surface metals to reduce corrosion from steam in fluid two-phase areas.	2023-Q1	$ 103,584	$ 400,857	$ 504,440
28	Four Corners - Potential Hydrogen (pH) Sampling Stations Replacement	The purpose of this project is to maintain unit reliability by replacing the existing potential hydrogen (pH) sampling stations and ensuring the continued availability of the five absorbers. The existing sampling stations have corroded and spare parts are obsolete. Permanent enclosure will protect the stations from future corrosion and shelter employees performing tasks at the absorber.	2023-Q1	$ 119,982	$ 594,950	$ 714,931
29	Four Corners - Potable Water Treatment System Upgrade	Comply with the Safe Drinking Water Act and Environmental Protection Agency (EPA) potable water disinfection requirements by increasing the residence time for chlorine-water contact. As currently configured the reverse osmosis system is unable to achieve the necessary disinfection.	2022-Q3	$ 900,667	$ 176,816	$ 1,077,483

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OTHER GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
30	Four Corners - Pulverizer Grinding Zone and Gear Drive Replacements - 2022	The purpose of this project is to maintain full load unit reliability by installation of new like-kind pulverizer grinding zone components and gear drive components as emergent failures or immediate need occurs throughout the 2022 calendar year.	2022-Q4	$ 906,104	$ 911,336	$ 1,817,440
31	Four Corners Unit 5 - Reverse Air Fan Inlet Damper Replacement	The purpose of this project is to maintain Four Corners Unit 5 reliability by replacing the reverse air fan dampers so that proper seal and operation of the reverse air system can be achieved. The installed dampers no longer stroke or seal properly. Inability to properly seal or operate the reverse air system will lead to accelerated fabric filter bag degradation and replacement, placing the unit at increased risk of derate or extended outage.	Various	$ 51,074	$ 604,706	$ 655,780
32	Four Corners Unit 4 - Reverse Air Fan Inlet Damper Replacement	The purpose of this project is to maintain Four Corners Unit 4 reliability by replacing the reverse air fan dampers so that proper seal and operation of the reverse air system can be achieved. The installed dampers no longer stroke or seal properly. Inability to properly seal or operate the reverse air system will lead to accelerated fabric filter bag degradation and replacement, placing the unit at increased risk of derate or extended outage.	Various	$ 50,005	$ 595,659	$ 645,664
33	Four Corners Units 4 and 5- Sootblower Motor Control Center Replacement	The purpose of this project is to maintain Unit reliability by replacing the Insertable Kinetic and Insertable Rotating Sootblower Motor Control Center (MCCs) that are approaching the end of their serviceable life. The MCCs are obsolete and replacement parts are difficult to find.	Various	$ 105,827	$ 1,329,913	$ 1,435,740
34	Four Corners Units 4 and 5 - South #1 Hydrobin Cone Replacement	The purpose of this project is to comply with 40 CFR; Part 423 EPA Effluent Limitation Guidelines (ELG) and Part 257 Coal Combustion Residual (CCR). The South #1 Hydrobin is in poor condition and is approaching the end of the serviceable life.	2023-Q2	$ 69,918	$ 698,078	$ 767,996
35	Four Corners Units 4 - South Train Lime Weigh Belt Feeders Replacement	The purpose of this project is to maintain unit reliability. The lime weigh belt feeders are approaching the end of their serviceable life and require replacement. Replacement parts are obsolete. Equipment must be removed to be repaired.	2022-Q3	$ 255,515	$ 310,400	$ 565,915
36	Four Corners Units 4 - T-621 Auxiliary Transformer Replacement	The purpose of this project is to maintain unit reliability. The Unit 4 auxiliary transformer T-641 was found to be in poor condition during the 2016 Outage. Power and control cables are also deteriorated and in poor condition and are nearing the end of the serviceable life.	2023-Q2	$ 755,964	$ 1,186,164	$ 1,942,128
37	Four Corners Units 4 and 5- Waste Oil Secondary Containment	The purpose of this project is to comply with the plant's Spill Prevention, Control, and Countermeasure (SPCC) plan. Current oil storage location is south of the SO2 building, and is without a containment area set up to prevent the accidental discharge of waste oil.	2023-Q2	$ 76,345	$ 828,417	$ 904,761
38	Motors / Pumps / Valves	Execute both scheduled and emergent motor, pump, and valve replacement projects across the fossil fleet.	Various	$ 10,083,084	$ 12,205,692	$ 22,288,776
39	Ocotillo Combustion Turbine Unit 3 Long Term Service Agreement 2022	Parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	2022-Q4	$ 537,444	$ 890,799	$ 1,428,243
40	Ocotillo Combustion Turbine Unit 4 Long Term Service Agreement 2022	Parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	2022-Q4	$ 417,806	$ 1,000,302	$ 1,418,108
41	Ocotillo Combustion Turbine Unit 5 Long Term Service Agreement 2022	Parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	2022-Q4	$ 459,572	$ 963,143	$ 1,422,714
42	Ocotillo Combustion Turbine Unit 6 Long Term Service Agreement 2022	Parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	2022-Q4	$ 407,711	$ 1,009,633	$ 1,417,344
43	Ocotillo Combustion Turbine Unit 7 Long Term Service Agreement 2022	Parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	2022-Q4	$ 446,566	$ 976,378	$ 1,422,945
44	Ocotillo - Replacement of OC Cooling Tower Mechanical Access Platforms and Walkways	The purpose of this project is to replace the existing removable access walkway that was provided with the new cooling tower. The existing removable walkway does not allow personnel to access the gearboxes without fall protection and does not provide access all around the gearbox.	2022-Q4	$ 1,585	$ 218,382	$ 219,967

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OTHER GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
45	Outage Discovery	Emergent capital replacements that can only be identified by visual inspection during plant outages.	Various	$ 1,136	$ 8,429,671	$ 8,430,807
46	Plant Tools	Ensure the timely replacement of plant tools in the Fossil Generation Fleet to maintain unit reliability.	Various	$ 259,952	$ 545,093	$ 805,045
47	Redhawk - 1 & 2 Inlet Chillers w/ Thermal Energy Storage (TES)	The purpose of this project is to improve performance of the site units at high ambient temperatures when peak demand is highest. Chiller installation will allow for increased power during hot summer months and year round.	2023-Q2	$ 7,407,742	$ 48,366,816	$ 55,774,558
48	Redhawk - 2A Reheat Outlet Header Replacement	The purpose of this project is to maintain reliability of the HRSG Reheater, safety of plant personnel, and lessen the chance of leaks.	2023-Q1	$ 144,419	$ 2,312,235	$ 2,456,654
49	Redhawk - Brine Solids Drying Pond Re-Lining	The purpose of this project is to maintain environmental compliance by replacing the liner which is at the end of service life.	2022-Q3	$ 10,729,618	$ 482,926	$ 11,212,543
50	Redhawk - Duct Burner Controls Replacement	Purpose of this project is to maintain unit reliability. This project will replace the existing Duct Burner obsolete Programable Logic Controllers (PLCs), replace analog flame scanners with digital flame scanners, install new instrument air cooling system for microprocessors on flame scanners, and rebalance and improve existing purge air cooling system for optical section of flame scanners.	Various	$ 281,820	$ 1,031,625	$ 1,313,445
51	Sundance - 1-10 Inlet Chillers w/ Thermal Energy Storage (TES)	The purpose of this project is to improve performance of plant at high ambient temperatures when peak demand is highest. Chiller installation will allow for increased power during hot summer months and year round.	2023-Q2	$ 6,637,765	$ 42,748,941	$ 49,386,707
52	Saguaro - New Firewater System	The purpose of this project is to ensure continued compliance with National Fire Protection Association (NFPA) 25, section 4.1.5, to correct the deficiencies in the current firewater system.	2022-Q4	$ 4,205,032	$ 558,464	$ 4,763,496
53	Saguaro - Replace Gas Turbine (GT) Unit 3 Generator Breaker	The purpose of this project is to maintain unit reliability by replacing the main generator breaker in Gas Turbine Unit 3, as it is approaching the end of design life.	2023-Q1	$ 507,328	$ 2,760,073	$ 3,267,401
54	Seasonal Readiness/Heat Trace	Execute both scheduled and emergent heat trace replacement projects across the fossil fleet.	2022-Q3	$ 2,201,012	$ 416,352	$ 2,617,364
55	Sundance Unit 1 - Replace the High Pressure Compressor rotor stages 3 through 5 blades	The purpose of this project is to ensure unit reliability. Replacement of the blades in stages 3-5 to protect against catastrophic failure.	Various	$ 1,582	$ 95,808	$ 97,390
56	Sundance Unit 6 - Replace the High Pressure Compressor rotor stages 3 through 5 blades	The purpose of this project is to maintain reliability. Replacement of the blades in stages 3-5 will reduce the risk of catastrophic failure from excessive dovetail pressure face coating wear.	Various	$ 1,583	$ 68,340	$ 69,924
57	Sundance Units 1-10 - Variable Bleed Value (VBV) Door/Hardware Upgrade and Sprint Nozzle Upgrades	The purpose of this project is to ensure unit efficiency and reliability. Engineering and operations troubleshooting revealed degradation in the sprint nozzles and VBV doors.	2022-Q4	$ 1,457,426	$ 344,773	$ 1,802,199
58	Tanks / Tank Re-lines	Execute both scheduled and emergent tank/tank liner replacement projects across the fossil fleet.	2023-Q2	$ 64,082	$ 404,029	$ 468,110
59	Water Systems/Membranes	Execute both scheduled and emergent water process system, water piping systems, and replacement reverse osmosis membrane projects across the fossil fleet.	Various	$ 2,293,111	$ 820,452	$ 3,113,562

NOTE: There may be variances in displayed values due to rounding.

OTHER GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
60	West Phoenix - Combined Cycle (CC) 1 Hydrogen Cabinet Replacements	The purpose is to install equipment that is up to standard hydrogen hazardous area codes, allowing for safer operation.	2023-Q1	$ 255,343	$ 365,489	$ 620,832
61	West Phoenix - Combined Cycle (CC) 2 Hydrogen Cabinet Replacements	The purpose is to install equipment that is up to standard hydrogen hazardous area codes, allowing for safer operation.	2023-Q1	$ 231,081	$ 448,408	$ 679,489
62	West Phoenix - Combined Cycle (CC) 3 Hydrogen Cabinet Replacements	The purpose is to install equipment that is up to standard hydrogen hazardous area codes, allowing for safer operation.	2023-Q1	$ 230,523	$ 448,281	$ 678,804
63	West Phoenix - Carbon Monoxide Catalyst	The purpose of this project is to ensure continued environmental compliance with the Title V air permit requirements by replacing the carbon monoxide (CO) catalyst for Unit 4. The CO catalyst must be replaced every 5 to 8 years in order to ensure proper performance and compliance.	2022-Q4	$ 107,492	$ 815,446	$ 922,939
64	West Phoenix - Condenser Replacement	The purpose of this project is to maintain unit reliability by replacing the condenser to ensure continued reliability of the Unit operation.	Various	$ 2,551,753	$ 8,744,734	$ 11,296,488
65	West Phoenix - Combustion Turbine 5A Long Term Maintenance Plan Parts	The purpose of this project is to acquire replacement parts from the Original Equipment Manufacturer (OEM) as necessary to ensure quick and efficient repairs for reliability purposes.	2022-Q4	$ 277,536	$ 1,541,005	$ 1,818,541
66	West Phoenix - Combustion Turbine 5B Long Term Maintenance Plan Parts	The purpose of this project is to acquire replacement parts from the Original Equipment Manufacturer (OEM) as necessary to ensure quick and efficient repairs for reliability purposes.	2022-Q4	$ 561,787	$ 1,286,085	$ 1,847,872
67	West Phoenix - Gas Turbine Cooling Water Fin Fan Heat Exchanger Replacement	The purpose of this project is to ensure unit availability and efficiency. Replacement of heat exchanger to improve reliability of unit. Existing heat exchange requires yearly cleaning and work arounds in order to cool to design limits.	2023-Q2	$ 140,078	$ 1,455,142	$ 1,595,220
68	West Phoenix - Hot Gas Path Overhaul	Extend the life of the turbine components by replacement of the hot gas path which will reach the Original Equipment Manufacturer (OEM) recommended hours for this system.	2022-Q4	$ 1,444,624	$ 959,383	$ 2,404,008
69	West Phoenix - Major Overhaul and Compressor Blade Replacement	The purpose of this project is to ensure unit reliability by completing a major overhaul and replacement of the compressor blades. The compressor blades have reached the end of service life.	2023-Q1	$ 10,435	$ 3,332,021	$ 3,342,456
70	West Phoenix - Replace Unit 5A and 5B Fire Suppression Systems	The purpose of this project is to maintain safety related systems for the gas turbines and minimize damages in case of fire. Parts for the current fire suppression system are obsolete per the servicing vendor.	2023-Q2	$ -	$ 426,369	$ 426,369
71	West Phoenix - Replacement of Combustion Components (Liners, Transition Pieces)	The purpose of this project is to maintain unit reliability of the Combined Cycle (CC) Unit 2 Gas Turbine by replacing the liners and transition pieces per the Original Equipment Manufacturer (OEM) recommended operating hour limits.	2023-Q2	$ -	$ 717,705	$ 717,705
72	West Phoenix - Right of Way License Payment	Right-of-Way license payment required for West Phoenix.	2023-Q1	$ -	$ 37,425	$ 37,425
73	West Phoenix - ZLD Centrifuge Elevated Concrete Deck Replacement	The purpose of this project is to maintain reliability of the Zero Liquid Discharge (ZLD) system through replacement of the Centrifuge Elevated Concrete Deck.	2023-Q1	$ 134,881	$ 1,049,275	$ 1,184,156
74	Yucca - Inlet Cooler Replacement	The purpose of this project is to maintain unit reliability. The evaporative cooler system is approaching the end of its useful life. Corrosion has produced holes in the evaporative cooler enclosure which allows debris to bypass the filtration and enter the turbine. This debris increases wear and decreases the life of the compressor components.	2022-Q4	$ 973,936	$ 1,822,050	$ 2,795,986

NOTE: There may be variances in displayed values due to rounding.

OTHER GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
75	Yucca - Install New Turbine Field Control Devices	The purpose of this project is to maintain unit reliability by updating the turbine controls system. This project will replace the original control system and will optimize the unit performance through improved monitoring and alarming capability and reduced troubleshooting time.	2023-Q1	$ 790,774	$ 982,021	$ 1,772,795
76	Yucca - Replace High Pressure Compressor (HPC) stage 3 thru 5 blades (SB 310)	The purpose of this project is to maintain reliability of the unit turbine by replacing capital components once they have seen an OEM recommended amount of starts. This will ensure proper turbine operation in accordance with OEM standards and will preclude turbine failure.	Various	$ 1,921	$ 293,120	$ 295,041
77	Yucca - Replace Motor Control Centers (MCCs) 3A and 3B	The purpose of this project is to upgrade aging infrastructure and consolidate the MCCs for current plant power requirements and also maintain compliance with NEC Section 430.107. MCC 3A and 3B are obsolete and are past their useful lifecycle.	2022-Q4	$ 244,057	$ 530,001	$ 774,058
78	Well Health	Execute scheduled and emergent projects related to well health.	Various	$ 959,725	$ 2,566,955	$ 3,526,680
79	Water Resource Management (WRM) Non-Production Wells	Projects that support the safety of our well fleet (i.e., Abandonments, Replacements etc.).	Various	$ 14,705	$ 655,702	$ 670,407
80	Trailing costs for projects in service prior to June 30, 2022	Includes multiple projects that went into service prior to June 30, 2022 but have trailing charges that extend into the Post Test Year period.		$ 30,380		$ 30,380
81	**Total Other Generation**			**$ 82,729,183**	**$ 218,199,264**	**$ 300,928,447**

NOTE: There may be variances in displayed values due to rounding.

RENEWABLE GENERATION
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost at June 30, 2022	Projected Costs to Close	Total Projected Costs
1	AZ Sun Battery	Add utility scale battery storage to the existing solar sites. The battery power output will match the solar output and will charge from solar during the day and discharge at night.	Various	$ 164,862,780	$ 15,301,815	$ 180,164,596
2	AZ Sun Battery 2	Add battery capacity to APS grid. 60MW total capacity at Chino Valley and Red Rock substations.	2023-Q2	$ 13,836,664	$ 104,125,348	$ 117,962,012
3	Agave Solar	Install 150MW photo-voltaic solar facility.	2023-Q2	$ 71,387,374	$ 170,072,177	$ 241,459,551
4	**Total Renewable Generation**			**$ 250,086,818**	**$ 289,499,340**	**$ 539,586,158**

NOTE: There may be variances in displayed values due to rounding.

EXECUTION COPY

AGREEMENT BETWEEN THE NAVAJO NATION AND ARIZONA PUBLIC SERVICE COMPANY REGARDING COAL-COMMUNITY TRANSITION

This Agreement Regarding Coal Community Transition (this "CCT Agreement") is between Arizona Public Service Company, an Arizona corporation ("APS" or "the Company"), and the Navajo Nation, a sovereign Native American Indian tribe (the "Nation"), (individually a "Party," and collectively the "Parties"), and is effective as of August 6th, 2021 (the "Effective Date").

Preamble

WHEREAS, APS is the operating agent for Four Corners Power Plant ("FCPP"), which is owned, as tenants in common with other third parties, including other electric utilities (collectively the "Participants"). APS began plant operations in its own capacity in 1963, with three wholly-owned electric generating units, and subsequently began additional operations on behalf of itself and the other plant Participants in 1969, with two additional co-owned electric generating units. The FCPP is located within the Nation near Farmington, New Mexico.

WHEREAS, since 1960, APS has conducted these operations in accordance with various lease agreements with the Nation, who holds beneficial ownership interests in the tribal trust land, upon which FCPP was constructed and continues to operate. These lease agreements (*i.e.*, the 1960 Indenture of Lease, the 1966 Supplemental and Additional Indenture of Lease, the 1985 Amendment and Supplement No. 1 to the Supplemental and Additional Indenture of Lease, and the 2011 Amendment and Supplement No. 3 to the Supplemental and Additional Indenture of Lease, (collectively, the "FCPP Site Lease Agreements")) were agreed to following substantial negotiation between APS, the Participants, and the Nation, and were subject to oversight and approval by the U.S. Department of the Interior. Under the current FCPP Site Lease Agreements, APS and the Participants may operate FCPP and occupy the underlying tribal trust lands until 2041.

WHEREAS, APS's interest in coal-fired generation within or near the Nation extends beyond FCPP. APS is also a co-owner, along with other third parties, of the Navajo Generating Station ("NGS"), which is located near Page, Arizona. NGS began operations in 1974 and permanently ceased operations in 2019. Along with the other NGS co-owners, APS is a party to the 2019 Extension Lease agreement with the Nation that governs NGS decommissioning, remediation, and site restoration. In addition, APS is the co-owner (along with a third party) and operating agent for the Cholla Power Plant ("Cholla"), which is located just south of the Nation near Holbrook, Arizona. APS began

operations at Cholla in 1962 and must cease coal-fired operations at this facility by April of 2025, pursuant to U.S. EPA Regional Haze regulations.

WHEREAS, in January of 2020, APS announced its intention to embark on an ambitious transition strategy aimed at becoming wholly reliant upon non-carbon emitting resources for electricity generation by 2050. A key component of this strategy is APS's commitment to cease reliance on coal-fired generation to serve its customers by 2031. With the closure of NGS, in 2019, and APS's cessation of coal-fired generation at Cholla in 2025, 2031 represents the end of APS's interests in coal-fired electricity generation within or near the Nation.

WHEREAS, in light of this transition, APS and the Nation entered into a non-binding Memorandum of Understanding, ("MOU") on November 6, 2020, upon which this CCT Agreement is based. The Parties intend that this CCT Agreement addresses community-transition assistance for coal-reliant communities in the vicinity of FCPP, Cholla, and NGS ("Coal-Community Transitions" or "CCT"). As provided, herein, this CCT Agreement shall provide for: (1) APS's commitment of financial support for CCT-related programs within the Nation, as specified within Paragraph 1(a) of this CCT Agreement ("CCT Financial Commitment"), (2) the expansion of electric infrastructure within the Nation ("Tribal Electrification"), (3) development opportunities for renewable energy resources developed within or nearby the Nation ("Tribal Renewable Energy Projects"), (4) general economic development within the Nation ("Tribal Economic Development"), and (5) the Nation's pursuit of additional water resources ("Tribal Water Rights").

WHEREAS, APS and the Nation intend for this CCT Agreement to resolve the positions and assertions raised by the Nation within its Pre-Filed Testimony of Jonathan Nez, President of the Navajo Nation (dated October 2, 2020) within APS's 2019 retail rate proceeding (i.e., APS's ACC Application for Approval of Rates, Charges, and Schedules, Docket No. E-01345A-19-0236, hereinafter "2019 Rate Case"). The Parties consider the Nation's positions and assertions made within docket of the 2019 Rate Case to be a "claim" pursuant to 2 N.N.C. § 1964(F) (the "CCT Claims"), and hereby intend that this CCT Agreement shall resolve these CCT Claims.

NOW THEREFORE, in consideration of the mutual benefits and obligations set forth in this CCT Agreement, the Nation and APS (on its own behalf and not as operating agent of FCPP) agree that the Preamble is made a part of this CCT Agreement and further agree as follows:

1. APS Commitments. APS's sole CCT commitments are set forth below:

a. CCT Financial Commitment. Subject to the on-going approval of the Arizona Corporation Commission ("ACC") for APS to recover the costs of its CCT Financial Commitment, through its retail electricity rates, as further described below (hereinafter, "Approved Cost Recovery"), APS shall make a One Hundred Million Dollar ($100,000,000.00) cash payment to the Nation, which shall be paid to the Nation in equal Ten Million Dollar ($10,000,000.00) annual payments, over 10 years. APS's CCT Financial Commitment to the Nation pursuant to this CCT Agreement shall be limited to this $100,000,000 total payment. Approved Cost Recovery shall be a condition precedent to APS making each annual payment.

i. Approved Cost Recovery may: (a) be set forth in a dedicated cost-recovery mechanism, such as APS's currently proposed Advanced Energy Mechanism, (b) be included in APS's base electricity rates, (c) be included as part of a securitization transaction and bond offering, or (d) may be in another mechanism approved by the ACC, for APS cost recovery through its retail electricity rates. APS shall have the sole and reasonable discretion to propose the form of customer cost recovery for its CCT Financial Commitment, subject to the approval of the ACC.

ii. If, at any time, Approved Cost Recovery is not available to APS or is otherwise reduced, impaired, or eliminated by the ACC, APS's CCT Financial Commitment shall be reduced or eliminated accordingly. If the ACC does not authorize Approved Cost Recovery or authorizes reduced Approved Cost Recovery, APS shall continue to work with the Nation in good faith to secure future funding of APS's $100,000,000 CCT Financial Commitment, through Approved Cost Recovery in future ACC proceedings.

iii. For the avoidance of doubt, in the event that the ACC does not approve customer cost recovery for APS's CCT Financial Commitment, either in whole or in part, or otherwise revokes or reduces such recovery, APS shall be under no obligation to pay any resulting shortfall through funding or payments from APS's shareholder or any other source.

b. Tribal Electrification. As part of the Company's 2019 Rate Case, APS shall submit a proposal to the ACC to modify APS's Schedule 3 distribution line extension policy within the Navajo Nation, such that APS distribution lines can be extended up to 2,000 feet within the Navajo Nation at no cost to applicants residing or operating within the Nation. Except as expressly approved by the ACC, pursuant to APS's Schedule 3 distribution line extension policy, APS shall be under no obligation to develop or construct any extension to the Company's electricity distribution infrastructure within the Navajo Nation portion of APS's service territory. As part of APS's Tribal Electrification efforts, APS shall also:

i. Conduct or pay for a census of unelectrified homes and businesses in the APS service territory, within the Navajo Nation, to be completed within one year after the Effective Date;

ii. Based on the census prepared in accordance with Paragraph 1(b)(i) of this CCT Agreement, prepare an assessment, to be submitted to the ACC and the Nation, regarding the effectiveness of the 2,000 feet proposed modification to APS's Schedule 3 distribution line extension policy in terms of increasing home and business electrification within the Navajo Nation portion of APS's service territory;

iii. To the extent that the assessment prepared pursuant to Paragraph 1(b)(ii) of this CCT Agreement finds that home and business electrification could be increased materially over and above the electrification increase achieved by the initial 2,000 feet extension through additional extensions to APS's Schedule 3 distribution line extension policy (as determined by mutual agreement of the Parties), APS and the Nation shall work together in good faith to determine the specific length of that additional extension. To the extent that the Parties can agree to a length for an additional extension as provided in this Paragraph 1(b)(iii), APS shall then work in good faith to propose to the ACC such additional modifications to APS's Schedule 3 distribution line extension policy as necessary to achieve such extension. The Navajo Nation

reserves the right to unilaterally seek additional distribution line extensions in future ACC proceedings and such right is not limited by the assessment prepared pursuant to Paragraph 1(b)(ii) of this CCT Agreement; and

iv. Provide Ten Million Dollars ($10,000,000.00) to the Nation towards additional home and business electrification projects within the Navajo Nation portion of APS's service territory as part of APS's Tribal Electrification commitments over and above any costs incurred by APS in connection with any changes made to the Company's Schedule 3 line extension policy pursuant to this CCT Agreement. This $10,000,000 shall be paid to the Nation in equal annual One Million Dollar ($1,000,000.00) payments over 10 years from the Effective Date of this CCT Agreement, and split between $5,000,000 from APS's shareholder and $5,000,000 from APS customer-cost recovery but subject to the same limitations as APS's CCT Financial Commitment provided in Paragraph 1(a).

c. Tribal Renewable Energy Projects. To the extent approved by the ACC, APS shall issue two sets of requests for proposals ("RFP(s)") concerning Tribal Renewable Energy Projects and shall consult with the Nation as to the content of those RFPs, including without limitation the RFP selection criteria, prior to their issuance and APS shall collaborate with the Nation to consider input provided by the Nation as part of such consultation. Such RFPs shall be governed by the following:

i. RFP Set I – APS shall seek one or more location-targeted proposals, where one or more RFPs will be released and made public over a period of 24 months following the Effective Date of this CCT Agreement, seeking to procure at least 250 MW of renewable electricity generation capacity, to be constructed within the geographic boundaries of the Nation and with the intent to deliver electricity to APS customers.

ii. RFP Set II – APS shall seek one or more location-targeted proposals, where one or more RFPs will be released and made public over a period of 12 months after the date that APS stops relying upon FCPP for power generation, seeking at least 350 MW

of renewable electricity generation capacity to be constructed within, either, the geographic boundaries of the Nation or neighboring communities (no more than 50 miles from the geographic boundaries of the Nation) and with the intent to deliver electricity to APS customers. For purposes of this CCT Agreement, the Parties agree that if, during any period of six (6) consecutive months, both, FCPP does not generate electric energy and all FCPP ancillary systems necessary for maintaining future plant electricity generation have been shutdown, then APS shall be considered to no longer rely upon FCPP for power generation.

iii. To the extent not inconsistent with ACC requirements, the Parties agree that, among those proposals received in response to the RFPs issued pursuant to this CCT Agreement, selection of any proposal shall be governed by a two-tiered approach; whereby, (1) the Nation shall provide input to APS regarding the submitted proposals, and (2) after accounting for the input and preferences provided by the Nation, APS shall then have the sole discretion whether or not to select one or more of such proposals for procurement. For the avoidance of doubt, APS shall not be required to select any Tribal Renewable Energy Project for procurement, unless a given project satisfies APS's RFP selection criteria as APS determines based upon evaluation of whether a given project can reliably serve APS customers at a reasonable customer cost. To the extent that any or all selected Tribal Renewable Energy Projects require ACC approval (or any other regulatory approval by a governmental body), or if APS elects to seek ACC approval for such selected Tribal Renewable Energy Projects in order to ensure project cost recovery, such approval(s) shall be a condition precedent to the effectiveness of any contract between APS and any Tribal Renewable Energy Project. APS's selection criteria shall give preference to proposals associated with renewable energy projects located in the same geographic vicinity as FCPP or NGS, but such location shall not be a requirement for selection of a given proposal, so long as all proposals are within the boundaries of the Nation or neighboring communities as provided herein (Paragraphs 2(c)(i) or 2(c)(ii)).

iv. For the purposes of transmission line development to support the delivery of power from Tribal Renewable Energy Projects, APS shall contribute Two Million Five Hundred Thousand Dollars ($2,500,000.00) per year to the Nation, which shall be funded by APS's shareholder, during the time period starting when APS stops relying upon FCPP for power generation (or 2032, whichever is earlier) and ending at the end of 2038. In the year in which APS stops relying upon FCPP for power generation, the amount owed the Nation shall be calculated using a pro rata share of the year remaining after the date on which APS stops relying upon FCPP for power generation. Payment to the Nation for the pro-rated portion of the first year in which APS stops relying upon FCPP for power generation shall be delivered within thirty (30) days of the date on which APS stops relying upon FCPP for power generation. Payments to the Nation shall be due on January 1 of each following year.

v. In the event that APS selects such a Tribal Renewable Energy Project to serve APS native load (as defined by the Federal Energy Regulatory Commission), as provided in this Paragraph 1(c), APS shall preserve its transmission service reservation as necessary to deliver that procured generation capacity to APS native load.

d. Tribal Economic Development. APS shall contribute One Million Two Hundred and Fifty Thousand Dollars ($1,250,000.00), distributed over five years through equal annual payments, funded by APS's shareholder, to a Navajo Nation economic development organization, which shall be designated by the Nation. APS's $1,250,000 commitment shall be paid to such designated Navajo Nation economic development organization in five equal annual payments of Two Hundred and Fifty Thousand Dollars ($250,000) and shall be paid during the two years prior to the date that APS stops relying upon FCPP for power generation and the three years thereafter.

e. Tribal Water Rights. APS shall support the Nation's pursuit of water rights from the San Juan River that are currently associated with FCPP and San Juan Generating Station. APS currently possesses a fee simple interest in certain of these rights, which shall revert to BHP Billiton ("BHP").

Such reversion occurs upon the earlier of on or about September 21, 2106 or the completion of final decommissioning of FCPP and final reclamation with Phase III bond release at the Navajo Mine. The Nation shall lead discussions with BHP, and APS shall provide the Nation support, including making appropriate introductions, providing supporting background information, and encouraging BHP to engage with the Nation in order to effectuate the transfer of FCPP-related water rights from BHP to the Nation.

f. Additional CCT Resources and Support. In addition, APS shall support the Nation, and other coalitions that may develop, in seeking to secure federal, state, or other funding for CCT funding, assistance, and commitments of resources, as requested. APS shall also support and encourage the other FCPP Participants to participate in making similar CCT commitments of support. Any funds achieved through these venues will be additive to the CCT commitments made by APS within this CCT Agreement.

g. APS Employee Re-Deployment. APS shall also prepare job re-deployment offers within the APS organization to all APS employees at Cholla and FCPP at least six months prior to the date when APS ceases relying upon Cholla and FCPP, respectively, for power generation.

2. Navajo Nation Commitments. The Nation's commitments to APS shall be as follows:

a. FCPP Cost Recovery. The Nation shall provide Public Support for APS's efforts to secure cost recovery for APS's investments into FCPP, including recently installed selective catalytic reduction pollution controls. As used in this CCT Agreement, the term "Public Support" shall include, without limitation, providing supportive testimony, public comments, briefings, or other public expressions, as necessary or appropriate to display support for a given matter or issue addressed herein. The Nation and APS shall take all practicable efforts to consult with one another and collaborate as to the proper method and venue for Public Support as to a given matter or issue. The Nation shall provide Public Support for the Company's FCPP-related cost recovery efforts within APS's pending 2019 Rate Case. In addition, as to any future proceeding before the ACC where APS elects to pursue

securitization to secure cost recovery for APS's investments into FCPP, the Nation shall provide Public Support for such securitization but only if that securitization transaction is also expressly intended to provide cost recovery for APS's commitment of CCT-related financial resources, as provided in Paragraphs 1(a) and 1(b) of this CCT Agreement. If the ACC has not yet otherwise approved customer cost recovery for APS's commitment of CCT-related financial resources, as provided in Paragraphs 1(a) and 1(b) of this CCT Agreement, then in no event shall APS pursue a securitization transaction involving APS's investments into FCPP without also including funding for such commitment of CCT-related financial resources as part of that proposed securitization transaction.

b. Clean Investment Cost Recovery. The Nation shall provide Public Support for APS's efforts in the 2019 Rate Case to secure direct and immediate cost recovery or financing for APS's investments into renewable or clean electricity or energy generation technologies or facilities, including infrastructure necessary to deliver, store, or beneficially convert such electricity or energy ("Clean Investment Cost Recovery").

    i. "Clean" electricity generation technologies or facilities shall mean any non-carbon emitting resource but excluding nuclear energy. Clean Investment Cost Recovery may include APS's proposed Advanced Energy Mechanism ("AEM"), other customer surcharges supporting renewable or clean energy or electricity technologies, securitization of retiring APS assets and the use of bond proceeds for APS investments into renewable or clean energy or electricity technologies, or other APS support mechanisms for clean or renewable energy or electricity cost recovery or finance.

    ii. The Nation shall provide such Public Support for APS's Clean Investment Cost Recovery efforts within APS's pending 2019 Rate Case or at any other time before APS stops relying upon FCPP for power generation.

c. CCT Cost Recovery. The Nation shall provide Public Support for APS's seeking customer cost recovery through the Company's retail electricity

rates in proceedings before the ACC regarding APS's commitment of CCT-related resources, as provided in Paragraph 1 of this CCT Agreement. The Nation's Public Support for customer cost recovery associated with APS's commitment of CCT resources, payments, costs, or expenses (as provided in this CCT Agreement) may involve, without limitation, the use of direct customer surcharges or other immediate cost-recovery mechanisms used for clean or renewable electricity or energy technologies (such as the AEM adjustor), the use of securitization bond proceeds to fund APS's CCT commitments provided in this CCT Agreement, inclusion within APS's base rates for retail electricity customers, or other forms of APS customer cost recovery. The Nation shall provide such Public Support for customer cost recovery as to APS's CCT commitments provided in this CCT Agreement within APS's pending 2019 Rate Case or at any other time before the ACC until the ACC has approved the entire sum of all APS commitments of financial resources related to CCT as expressly provided in Paragraphs 1(a) and 1(b) of this CCT Agreement.

d. CCT Durability. The Nation acknowledges that APS's CCT commitments, as described in this CCT Agreement, are not intended to establish any precedent or commitment to provide further CCT assistance to the Nation, its members, or political subdivisions. For the purposes of this Paragraph 2(d), references to APS shall include APS, its affiliates, its parent corporation (or any shareholders thereof), its subsidiaries, and its successors and assigns, either presently existing or formed in the future.

    i. It is the intention of the Parties that so long as APS is performing its obligations under this CCT Agreement or after APS has completed the performance of all of its obligations under this CCT Agreement, including providing full payment for all (a) ACC-approved financial commitments and (b) APS's shareholder financial commitments in Paragraph 1 of this CCT Agreement, APS's performance under this CCT Agreement shall fully and finally fulfill any and all obligations APS may have, now or in the future, for any CCT-related matter as to the Company's ownership interests in FCPP, NGS, or Cholla, including without limitation the CCT Claims or any other obligations to provide for a just and equitable transition away from the economic benefits provided to

the Navajo Nation by coal-fired electricity generation or coal mining or to otherwise provide economic, in-kind, logistical, infrastructure, or other forms of support for the Navajo Nation to address social, economic, or environmental impacts or effects related to historical coal-related energy development (collectively "CCT Related Matters"). For the avoidance of doubt, nothing in this CCT Agreement shall relieve APS of its obligations related to environmental matters, including any environmental investigation or remediation, arising from operations at or near FCPP, NGS, or Cholla, nor does anything in this CCT Agreement affect any claims, demands, actions or causes of action, or suits of law or in equity that the Nation may have against APS now or in the future regarding any such environmental matters at or near FCPP, NGS, or Cholla.

ii. Therefore so long as APS is performing its obligations under this CCT Agreement or after APS has completed the performance of all of its obligations under this CCT Agreement, including providing full payment for all (a) ACC-approved financial commitments and (b) APS's shareholder financial commitments in Paragraph 1 of this CCT Agreement, the Nation hereby fully, unconditionally, and irrevocably releases, acquits, remises, and forever discharges APS from having any further obligations, duties, or liabilities, along with any and all claims, demands, actions or causes of action, or suits of law or in equity, to the Nation for any CCT Related Matters (known or unknown, past, present, or future, suspected to exist or not suspected to exist, anticipated or not anticipated, which have arisen, are now arising, or hereafter may arise out of or relate to any CCT Related Matters). In addition, following the Effective Date, the Nation shall not directly or indirectly request, seek, demand, or otherwise condition any future approval or agreement (with or from the Nation or another party, including without limitation the United States government) upon the provision of any further support or commitment of resources by APS for any CCT Related Matters except as otherwise provided in this CCT Agreement.

iii. The Nation recognizes and acknowledges that APS's CCT commitments provided in Paragraph 1 of this CCT Agreement shall be on behalf of itself solely in regards to each of its Navajo-located or Navajo-adjacent coal-fired power plants—FCPP, Cholla, and NGS.

3. 2019 Rate Case Settlement. The Parties agree to negotiate in good faith to seek a potential settlement of the 2019 APS Rate Case in whole or in part. The Parties agree to make best efforts to obtain the support of APS's CCT commitments pursuant to this CCT Agreement from other parties to or intervenors in the 2019 APS Rate Case. Neither Party may enter into any settlement or stipulation as to the resolution of 2019 APS Rate Case that does not include APS's CCT commitments pursuant to this CCT Agreement, without the written consent of the other Party.

4. Dispute Resolution; Jurisdiction.

   a. Initial Dispute Resolution. If any dispute, claim, demand, default, or controversy arises under this CCT Agreement (a "Dispute"), the Party raising the Dispute must give written notice of the Dispute to the other Party, including a description of those particulars reasonably available at that time and a proposal for resolving the Dispute. Each Party shall appoint a senior representative, and the two representatives shall endeavor in good faith to negotiate a resolution of the Dispute within ten (10) days following the delivery of written Dispute notice. The Nation shall not commence formal dispute resolution pursuant to Paragraph 4(b) until thirty (30) days after the first meeting of the Parties seeking to resolve the Dispute (or such extended time period as to which the parties may mutually agree). The requirements of this subparagraph are conditions precedent to the Nation's right to bring a claim, as set forth in subparagraph (b) below.

   b. Choice of Forum. The Nation agrees that any claims or disputes brought by the Nation and arising under or relating in any way to this CCT Agreement shall be brought only in the courts of the State of Arizona. The interpretation and performance of, and any claims arising under or relating in any way to, this CCT Agreement shall be governed by the laws of the State of Arizona, excluding any conflict-of-law rule or principle that

might apply the law of another jurisdiction. The Nation irrevocably agrees that it shall not plead or raise as a defense, in the exclusive Arizona state court forum identified in this Paragraph, any right or claim of right to the requirement of exhaustion of tribal court remedies, prior to the commencement of litigation proceedings, even if any such tribal forum would have concurrent jurisdiction over any such dispute but for such agreement. The Nation irrevocably agrees it will not bring any dispute arising under this CCT Agreement in any tribal court or before any other tribal tribunal, forum, council or other adjudicative body whether or not such forum now exists or is hereinafter created. The provisions of this Paragraph are subject to specific performance. The execution, delivery and performance by the Nation of this CCT Agreement and the obligations contained herein have been duly authorized by all necessary Tribal governmental action, and do not require any consent or approval not heretofore obtained of any Tribal officer or Tribal body. For the avoidance of doubt, the Parties acknowledge that the Nation's irrevocable agreement not to plead or raise as a defense the doctrine of exhaustion of tribal remedies does not constitute a waiver of the Nation's immunity from suit.

c. Tribal Jurisdiction. Notwithstanding any term or condition within this CCT Agreement, this CCT Agreement shall not constitute a "consensual relationship" under *Montana v. United States,* 450 U.S. 544 (1981), as to any matter except as explicitly mentioned or addressed by this CCT Agreement. APS shall not be deemed to have consented to the jurisdiction of the Nation's courts, legislature, executive branch, or any other governmental subdivision, body, or entity of the Nation, and the Nation hereby irrevocably agrees to not assert jurisdiction to the contrary.

d. Existing Agreements. APS and the Nation agree that nothing contained within this CCT Agreement shall be construed to constitute an amendment or change to the FCPP Site Lease Agreements or the 2019 Extension Lease associated with NGS (including without limitation the "covenant not to regulate" contained therein) or any other agreement between the Parties. Nor shall this CCT Agreement constitute or represent any encumbrance on the lands subject to the FCPP Site Lease Agreements or the 2019 Extension Lease associated with NGS.

e. Sovereign Immunity. For the avoidance of doubt, nothing contained in this Agreement shall be interpreted as constituting a waiver, express or implied, of the sovereign immunity of the Nation.

5. Termination Rights. Prior to the expiration of the Term of this CCT Agreement, this CCT Agreement may be terminated by the written mutual consent of the Parties, in which case all obligations of each Party to this CCT Agreement shall end and the provisions of this CCT Agreement shall have no further force and effect.

a. Notwithstanding the forgoing in this Paragraph 5, APS may terminate this CCT Agreement, upon 30 days prior written notice, if the Nation materially breaches or otherwise fails to fulfill any of its obligations, duties or promises under Paragraph 2 of this CCT Agreement or otherwise fails to follow the procedures for Dispute Resolution provided in Paragraph 4 of this CCT Agreement. Materiality in this provision shall be governed by reference to the overall benefit to APS in light of the entirety of this CCT Agreement. As a condition precedent to APS having rights to terminate this CCT Agreement under this Paragraph, APS must first follow the procedures for Initial Dispute Resolution outlined in Paragraph 4(a) of this CCT Agreement, as to any such alleged material breach or failure by the Nation.

b. The Nation may terminate this CCT Agreement, upon 30 days prior written notice, if APS materially breaches or otherwise fails to fulfill any of its obligations, duties, or promises under Paragraph 1 of this CCT Agreement or otherwise fails to follow the procedures for Dispute Resolution provided in Paragraph 4 of this CCT Agreement. Materiality in this provision shall be governed by reference to the overall benefit to the Nation in light of the entirety of this CCT Agreement. As a condition precedent to the Nation having rights to terminate this CCT Agreement under this Paragraph, the Nation must first follow the procedures for Initial Dispute Resolution outlined in Paragraph 4(a) of this CCT Agreement, as to any such alleged material breach or failure by APS.

6. ACC or Other Governmental Approvals or Authorizations. With respect to any and all provisions of this CCT Agreement that require, condition, or otherwise contemplate the authorization or approval from the ACC or other governmental

body for any matter or issue governed by this CCT Agreement, such regulatory approval means that the ACC or other governmental body has given final approval or authorization, to the extent necessary, and such approval or authorization is not unreasonably conditioned and otherwise does not contain additional unreasonable requirements that would frustrate the purpose for which such approval or authorization was sought. In addition, with respect to any necessary authorizations or approvals from the ACC pursuant to Paragraph 1(c) for Tribal Renewable Energy Projects, regulatory approval under this CCT Agreement means that ACC authorization or approval is neither unreasonably conditioned nor includes additional unreasonable requirements that would otherwise be inconsistent with regulatory approval for a renewable electricity generation project that was not located within or nearby the Navajo Nation.

7. Miscellaneous. In addition to the forgoing, the following terms and conditions govern the implementation and operation of this CCT Agreement:

   a. Term. Unless otherwise terminated pursuant to the terms of this CCT Agreement, the Term of this CCT Agreement shall extend from the Effective Date until the later of: (1) December 31, 2038 or (2) the end of the calendar year when APS completes all of its obligations under this CCT Agreement.

   b. Execution in Counterparts. This CCT Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which constitute but one agreement. Any counterpart may be delivered by facsimile transmission or by electronic communication in portable document format (.pdf) or tagged image format (.tif), and the Parties agree that their electronically transmitted signatures shall have the same effect as manually transmitted signatures.

   c. No Third-Party Beneficiaries. This CCT Agreement is solely for the benefit of the Parties and their respective permitted successors and permitted assigns, and except as expressly provided herein, this CCT Agreement shall not otherwise be deemed to confer upon or give to any other third party any remedy, claim, liability, reimbursement, cause of action or other right.

   d. Nation's Representations. The Nation hereby represents and warrants that:

i. The Nation is a federally recognized Indian Tribe and has the full power and authority to make, deliver and perform this CCT Agreement and its obligations hereunder and has taken all action required under the Nation's and federal law to execute, deliver and perform its obligations under this CCT Agreement.

ii. This CCT Agreement constitutes the legal, valid, and binding obligation of the Nation, enforceable against the Nation in accordance with the terms of this CCT Agreement and pursuant to the authority of the Nation's Attorney General to settle "claims" under 2 N.N.C. § 1964(F) Except for the express representations and warranties provided by the Nation herein, the Nation makes no other representations or warranties, express or implied, of any kind whatsoever.

iii. The representations and warranties set forth in this Paragraph shall survive the execution and delivery of this CCT Agreement.

e. APS's Representations. APS hereby represents and warrants to the Nation that:

i. This CCT Agreement constitutes the legal, valid, and binding obligation of APS, enforceable against APS in accordance with its terms.

ii. APS is an entity in good standing and authorized to conduct business in the states of Arizona and New Mexico.

iii. Except for the express representations and warranties provided by APS herein, APS makes no other representations or warranties, express or implied, of any kind whatsoever.

iv. The representations and warranties set forth in this Paragraph shall survive the execution and delivery of this CCT Agreement.

f. Limitation on Damages. Neither Party shall be liable to the other Party for any indirect, consequential, special, or punitive damages for any actions resulting from or arising out of this CCT Agreement.

g. Integration. This CCT Agreement, together with any Exhibits, if any, constitute the entire agreement and understanding between the Nation and APS with respect to the subject matter hereof and supersede all prior agreements relating to the subject matter hereof, including the MOU between the Parties dated November 6, 2020.

h. Amendments. This CCT Agreement may only be amended, modified or supplemented by an instrument in writing executed by duly authorized representatives of the Nation and APS.

i. Waiver. No waiver of any provision of this CCT Agreement shall be effective unless set forth in writing signed by the Party granting such waiver, and any such waiver shall be effective only to the extent it is set forth in such writing. The failure of the Nation or APS to enforce any of the provisions of this CCT Agreement, or the waiver thereof, shall not be construed as a general waiver or relinquishment on its part of any such provision in any other instance, or of any other provision in any instance. No single or partial exercise of any right under this CCT Agreement shall preclude any other or further exercise thereof or the exercise of any other right; and no waiver of any breach of or default under any provision of this CCT Agreement shall constitute or be construed as a waiver of any subsequent breach of or default under that or any other provision of this CCT Agreement.

j. Severability. Any term, covenant or condition in this CCT Agreement that to any extent is invalid or unenforceable in any respect in any jurisdiction shall, as to such jurisdiction, be ineffective and severable from the rest of this CCT Agreement to the extent of such invalidity or prohibition, without impairing or affecting in any way the validity of any other provision of this CCT Agreement, or of such provision in other jurisdictions. The Parties shall use good faith efforts to replace any provision that is ineffective by operation of this Paragraph with an effective provision that as closely as possible corresponds to the spirit and purpose of such ineffective provision.

k. Relationship of the Parties. The relationship between the Nation and APS shall not be that of partners, agents or joint ventures for one another, and nothing contained in this CCT Agreement shall be deemed to constitute a partnership or agency agreement between them for any purposes, including federal income tax purposes. The Nation and APS, in performing any of their obligations hereunder, shall be independent contractors or independent parties and shall discharge their contractual obligations at their own risk.

l. Survival. The obligations hereunder that, by their sense and context, are intended to survive termination of this CCT Agreement shall survive the expiration or termination of this CCT Agreement to the extent necessary to give them full effect regardless of whether any provision is expressly noted as surviving the expiration or termination of this CCT Agreement.

m. Interpretation, Rules of Construction. Each Party has had an adequate opportunity to review each and every provision of this CCT Agreement and to submit the same to legal counsel for review and advice. Based on the foregoing, the rules of construction, if any, that a contract be construed against the drafter or that ambiguities shall be resolved in favor of the Nation shall not apply to interpretation or construction of this CCT Agreement.

n. Notices. All notices, approvals, disapprovals or elections required or permitted to be given under this CCT Agreement shall be in writing and shall be: (i) delivered personally, (ii) mailed, certified or registered mail, return receipt requested, (iii) sent by facsimile transmission, or (iv) sent by Federal Express or other professional carrier, to the Parties at the following addresses:

If to the Nation:

Office of the President and Vice President
The Navajo Nation
P.O. Box 7440
Window Rock, Navajo Nation (Arizona) 86515
Fax: (928) 871-4025

And to:

Navajo Nation Department of Justice
Office of the Attorney General
P.O. Box 2010
Window Rock, Navajo Nation (Arizona) 86515
Fax: (928) 871-6177

If to APS:

Vice President, Sustainability
Arizona Public Service Company
400 N. 5th Street, Mail Station: 9040
Phoenix, Arizona 85004
Fax: 602-250-3393

And to:

Pinnacle West Law Department, Office of General Counsel
Pinnacle West Capital Corporation
400 N. 5th Street, Mail Station: 8695
Phoenix, Arizona 85004
Fax: 602-250-3393
Telephone: 602-250-3630

Notices shall be deemed given upon delivery or tender of delivery to the intended recipient; provided that notice sent by email or facsimile shall only be deemed received when either (i) the sender has electronic confirmation that it was sent to all Parties (and has retained a printed confirmation of the delivery to the applicable fax number or email address) or (ii) at least one addressee entitled to notice under this Paragraph for the applicable Party has acknowledged receipt of the transmission. Copies of notices are for informational purposes only, and a failure to give or receive copies of any notice shall not be deemed a failure to give notice. Any notice sent by the attorneys representing a Party shall qualify as notice under this CCT Agreement.

EXECUTION COPY

IN WITNESS WHEREOF, the parties have entered into this CCT Agreement as of the Effective Date.

The Nation:

NAVAJO NATION

By: _____

Date: 08.11.2021

Name: Jonathan Nez

Title: Navajo Nation President

By: _____

Date: 8/16/2021

Name: Doreen N. McPaul

Title: Navajo Nation Attorney General

APS:

ARIZONA PUBLIC SERVICE COMPANY, an Arizona corporation

By: _____

Date: August 6, 2021

Name: Jeffrey B. Guldner

Title: Chairman and Chief Executive Officer

DIRECT TESTIMONY OF MONICA WHITING

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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ATTACHMENT LIST

Drivers of J.D. Power (JDP) Customer Satisfaction; APS Performance for Residential and Business Customers ..... Attachment MW-01DR
Excerpt From EEI "Enhancing Customer Payment Approaches to Better Serve Residential and Small Business Customers" ..... Attachment MW-02DR

DIRECT TESTIMONY OF MONICA WHITING
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Monica Whiting. I am Vice President of Customer Experience and Communications, and Chief Customer Officer for Arizona Public Service Company (APS or Company). I am responsible for providing customer operations and services for APS's 1.3 million residential and business customers, with a dedicated focus on improving the customer experience. This includes managing the Customer Experience Center (the inbound call and service center), Customer Revenue Operations, Communications, Customer Experience Strategy, Solutions and Initiatives, and Business Customer Engagement. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have worked in the utility industry for nearly 30 years at public power and investor-owned utilities throughout the country. Some of those utilities continuously performed in the top quartile for customer satisfaction, while I others I helped successfully improve their overall customer experience and ranking in national surveys. Throughout my career, my focus has been on customers – their experiences interacting with the company, how the company effectively communicates with them, how the company gathers their voice and input to drive continuous improvement, and developing and delivering the products and services they use as part of their utility experience. Prior to coming to APS, I was the Vice President of Customer Experience and Communications, and Chief Customer Officer at Tampa Electric Company (TECO) & Peoples Gas Systems (PGS). Before that, I served as the Chief Customer Officer at Jacksonville Electric Authority (JEA). I also led and worked in various customer experience operations,

and communications and marketing roles for Colorado Springs Utilities. I earned my Bachelor of Arts degree in Public Relations and Journalism from the University of Southern California.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. Yes. I provided testimony in APS's 2019 Rate Case proceeding. I have also spoken on behalf of APS at Commission Open Meetings.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. I describe the Company's proposals to meet its customers' evolving needs and expectations. In addition to APS's responsibility to provide safe, reliable, and clean energy service, the proposals I describe recognize the Company's fundamental responsibility and commitment to deliver an excellent customer experience. Over the last couple of years, APS has made many improvements in customer service, including improved telephone service levels, improved digital usability and functionality, and new payment channels, among others. In addition to these improvements, industry and customer research and stakeholder input have pointed to additional ways to improve APS's customer experience. These include proposals for:

- Enhancing its current limited-income program to a two-tiered discount program to address APS's most vulnerable customers' energy burden, which includes an increased discount for those customers with the greatest financial hardship;
- Removing in-network customer payment fees in recognition of shifting customer expectations for electronic payment channels; and
- Adding two additional off-peak holidays for customers on time-of-use rates.

III. CUSTOMER EXPERIENCE IMPROVEMENTS

Q. HAS APS SEEN IMPROVEMENTS IN THE CUSTOMER EXPERIENCE?

A. Yes. Over the past two years, APS worked extensively with customers, stakeholders, and the Commission and has leveraged industry best practices to improve the customer experience – and the collective efforts are making an impact. As a result, APS's customers are experiencing positive improvements in the Company's services and products. The impact can be seen by improvements in a number of measures, including in J.D. Power (JDP) overall residential and business customer satisfaction. Attachment MW-01DR provides an explanation of JDP's customer satisfaction drivers and also shows APS's improvement in these drivers and overall satisfaction. The most recently available results show that, through the third quarter of 2022, APS moved into the second quartile for overall residential customer satisfaction when compared to large investor-owned utilities; and, through the second quarter of 2022, APS moved into the first quartile nationally for business customer satisfaction.

JDP customer satisfaction is determined based on customers rating six key drivers of satisfaction – Power Quality and Reliability (PQ&R); Price; Billing and Payment; Communication; Corporate Citizenship; and Customer Care (phone, digital and in-person). APS has improved in every driver of satisfaction. More specifically, the Customer Care driver, including both phone and digital customer care, has significantly improved to the first quartile. This driver's rise can be tied to several important improvements – for example, telephone service levels have improved to an average speed of answer below 60 seconds and approximately 75% of calls answered in 30 seconds or less. In addition, the Company implemented many digital best practices, including:

- Visual enhancements to the aps.com home and payment pages;

- Simplified links and content;
- Statewide Spanish language transactional capability;
- Improved navigation; and
- Enhancements to the outage center.

The Communications driver and attributes have also improved, as shown in Figure 1. Many of the attributes are a core measurement of the Company's Customer Education and Outreach Plan.

Figure 1. J.D. Power Quartile Improvements to Attributes and Key Indicators Shaped by Communications

J.D. Power Customer Satisfaction Attributes and Key Indicators Shaped by Communications	2021 Quartile	Q3 2022 Quartile	Trend
Efforts to Communicate Changes that Affect Account/Service	4	2	↑
Creating Messages that Get Your Attention	4	3	↑
Recall of Utility Communications	3	2	↑
Ease of Understanding Your Pricing Options	4	2	↑
Efforts to Help You Manage Your Monthly Usage	4	2	↑
Customer Awareness of Energy Efficiency/Conservation Programs	2	1	↑

The PQ&R driver also continues to have strong performance, remaining in the second quartile three-quarters of the way through 2022. Performance for this driver is tied to several important initiatives the Company has been working on, including new and improved Estimated Time of Restoration (ETR) allowing APS to communicate outage restoration times more effectively with customers, and proactive text and email alerts for planned and unplanned outages.

Additionally, APS has enhanced other alerts such as consumption notifications and bill payment notifications. Worth noting, in 2021, APS was ranked as an industry-leading utility nationally in best practices including perfect power, customers enrolled in online accounts, bill-ready alerts and the percentage of customers using their mobile app. While APS is proud of these improvements, the Company's goal continues to be listening to customers, and collaborating with stakeholders and the Commission, to improve the customer experience over the next several years and to become a top quartile ranking utility in overall residential and business customer satisfaction.

IV. PROPOSALS FOR LIMITED-INCOME CUSTOMERS

Q. PLEASE BRIEFLY DESCRIBE APS'S CURRENT ENERGY SUPPORT PROGRAM FOR LIMITED-INCOME CUSTOMERS.

A. APS offers the highest discount and funding for limited-income customers in Arizona. The APS Energy Support Program provides a 25% bill discount to all customers at or below 200% of the Federal Poverty Level (FPL), as described in Rate Rider E-3. Customers with qualifying medical equipment are eligible for a discount of 35%, as described in Rate Rider E-4.

Q. WHAT ARE THE BENEFITS OF APS'S CURRENT ENERGY SUPPORT PROGRAM?

A. APS's current Energy Support Program provides a simple and understandable discount to a qualifying customer's APS bill. Today's program has the following benefits:

- It supports the 200% FPL for enrollment in the program;
- It is simple and understandable for customers and assistance providers, who help customers enroll in the program;
- It provides customer certainty about the discount percentage participants will receive each month;

- It leverages the ability to "auto-enroll" customers who are approved for other assistance programs such as Low Income Home Energy Assistance Program (LIHEAP), Supplemental Nutrition Assistance Program (SNAP) or Emergency Rental Assistance Program (ERAP), which have income eligibility requirements at or below the APS Energy Support Program, so customers can be added to the Energy Support Program without having to apply separately for each program;
- It is efficient to administer; and
- It is designed thoughtfully, considering the financial impact of the program on other APS customers.

Q. DURING THE TEST YEAR, WHAT WAS THE NUMBER OF CUSTOMERS ENROLLED IN THE ENERGY SUPPORT PROGRAM AND WHAT WAS THE TOTAL SPEND BY APS ON THE ENERGY SUPPORT PROGRAM'S DISCOUNTS?

A. The number of customers enrolled in the Energy Support Program and receiving bill discounts under this program at the end of the Test Year was approximately 70,600. In the Test Year, APS provided discounts in the amount of $33.8 million. The average monthly discount received by participating customers was $36.33.

Q. IN ITS LAST RATE CASE, DID THE COMMISSION ASK APS TO CONSIDER CHANGES TO ITS LIMITED-INCOME PROGRAM? IF SO, PLEASE EXPLAIN.

A. Yes. The Commission directed APS to collaborate with stakeholders to develop and propose for the Commission's consideration a limited-income program focused on reducing a customer's energy burden.

APS held a series of stakeholder meetings to develop a limited-income program aiming to reduce the energy burden of APS's most vulnerable customers. Energy

burden is the amount of a customer's annual electricity bill divided by the customer's annual household income. Energy burden represents the concept that lower income customers pay a higher percentage of their total income for their utilities. Organizations represented in the stakeholder meetings included Wildfire, the National Consumer Law Center, American Association of Retired Persons (AARP), Arizona Center for Law in the Public Interest, Arizona Public Interest Research Group (PIRG), Earthjustice, Hopi Tribe, Residential Utility Consumer Office (RUCO), and Commission Staff. While a full stakeholder consensus on a new proposal was not achieved, the collaborative effort was productive, respectful, and cooperative. The group worked together to review the available data, consider possible program designs, and discuss how the proposed program would address the energy burden of limited-income customers. The stakeholder discussions, suggestions, and challenging questions shaped the tiered limited-income proposal being offered by APS below.

Q. PLEASE DESCRIBE APS'S TIERED LIMITED-INCOME PROPOSAL.

A. APS proposes to enhance its Energy Support Program to include a discount structure with two tiers based on household income, not exceeding 200% of the FPL. As demonstrated in Figure 2, customers with verified income levels between 0 to 75% of the FPL would receive a discount of 60% off of their monthly bill, capped at a discount of $165 per month. Customers with income levels between 75% to 200% of the FPL would continue to receive a 25% discount, as they do today, but capped at $95 per month. With this proposal, customers with qualifying medical equipment who currently qualify for E-4 would continue to receive an additional 10% discount above their corresponding tier discount, if they are on the 75% to 200% FPL tier, which equates to a 35% discount.

Figure 2. APS's Tiered Limited Income Proposal

FPL Level	Discount %	Maximum Monthly Discount
0 - 75%	60%	$165
>75% - 200%	25%	$95

The additional tiered discount provides a much bigger discount for customers with a higher energy burden and provides a significant discount for other limited-income customers, which lowers their energy burden as well. APS estimates that, of APS's currently participating customers, approximately 19,000 customers would be eligible to receive the proposed 60% discount and 52,000 would receive the proposed 25% discount.

Q. WHAT ARE THE BENEFITS OF A PROGRAM DESIGNED TO REDUCE THE ENERGY BURDEN WITH TIERED DISCOUNT LEVELS?

A. The 60% discount for customers who earn 0-75% of the FPL has a significant impact for this customer group's energy burden. For example, a single parent and child who earn 50% of the FPL will have an estimated energy burden of 18.6% if this family is not receiving a limited-income discount. With APS's current program, this family would receive a 25% discount and their energy burden would drop to 14%. With APS's proposed additional tiered discount, this family would receive a 60% discount and their energy burden would drop to 7.5%. Additionally, an elderly couple at 200% of the FPL that is not receiving a limited-income discount would have an estimated energy burden of 4.7%. Under APS's current program and under APS's proposed tiered discount program up to the cap, this elderly family would receive a 25% discount and their energy burden would reduce to 3.5%.

Q. WHAT IS THE ANTICIPATED COST OF THE TIERED LIMITED-INCOME PROPOSAL?

A. The cost of the proposed discount program is anticipated to be approximately $41.3 million, which is a $6.9 million operating cost increase compared to the current program. APS witness Jessica Hobbick provides in her testimony further explanation regarding the proposed program costs to support this proposed two-tiered discount program designed to address customer energy burden.

Q. DOES APS OFFER ADDITIONAL PROGRAMS FOR LIMITED-INCOME CUSTOMERS?

A. Yes. APS has additional assistance programs that provide discounts to qualified limited-income customers, as well as programs to help customers stay on top of their bills. The APS Crisis Bill Assistance provides up to $800 per year for eligible customers to cover their APS bill. APS provided $1.2 million APS Crisis Bill Assistance during the Test Year. Decision No. 78317 (November 9, 2021) increased the amount APS may spend on Crisis Bill Assistance to $2.5 million. The Company is requesting to continue the increased funding of $2.5 million for the program in future years.

APS also has a Limited-Income Weatherization DSM program, which provides qualified customers with energy-efficient home improvements aimed at reducing their energy consumption. In the Test Year, APS spent approximately $9.1 million on this program.

Additionally, qualified customers may receive up to $300 through the Salvation Army as part of the Salvation Army Project SHARE program. This program is funded in part through voluntary contributions by APS customers and employees,

with APS matching the employee donations. In the Test Year, the Company disbursed $361,439 through SHARE.

Q. WHAT EXTERNAL RESOURCES ARE AVAILABLE TO APS'S LIMITED-INCOME CUSTOMERS?

A. APS partners with over 100 community assistance partners and agencies (local, state, and federal providers) to connect customers with available funding to reduce and/or pay for their energy bills. APS's collaboration has focused on simplification for customers when applying for programs, working with community partners to identify those customers in need of assistance, and increasing communications and outreach. In the Test Year, APS customers received a total of $27.2 million in assistance from the external sources identified in Figure 3, which is in addition to the approximately $33.8 million of bill discounts provided under the Energy Support Program and $1.2 million provided in Crisis Bill Assistance.

Figure 3. Test Year External Utility Bill Assistance Programs

Program	Description	No. of Assistance Transactions (also called "guarantees"), Customers may receive multiple guarantees.	Amount
Low-Income Home Energy Assistance Program (LIHEAP)	Helps customers with their heating and cooling energy costs, bill payment assistance, energy crisis assistance, weatherization and energy-related home repairs.	5,200	$3.5 million
Emergency Rental Assistance Program (ERAP)	Offers eligible Arizona residents impacted by the COVID-19 pandemic up to $3,500 per month in combined rent and utility assistance.	45,200	$16.3 million
Unspecified APS and External Fund Source	Assistance guarantees submitted to APS that did not specify the source of the funding.	10,600	$6.8 million
Homeowners Assistance Fund (HAF)	Offers eligible Arizona residents impacted by the COVID-19 pandemic up to $3,500 per month in combined mortgage and utility assistance.	998	$0.6 million

V. PAYMENT FEE REMOVAL

Q. WHAT PAYMENT FEES APPLY CURRENTLY FOR APS CUSTOMERS?

A. Currently, payment fees charged by vendors and passed on to customers directly apply to payments made by credit cards, debit cards, Amazon Pay, Venmo, PayPal, kiosks and in-person retailers. These fees range from $1.50 to $2.95 per transaction and are currently paid by the customer.

Q. HAS THERE BEEN A SHIFT IN CUSTOMER EXPECTATIONS AND HOW BUSINESSES, INCLUDING UTILITIES, HANDLE THESE FEES?

A. Yes. Digital payments are commonplace today in multiple industries. According to the Edison Electric Institute (EEI):

> Today's residential and small business customers expect bill payment options from electric companies to be consistent with what they experience in other areas of their lives and business interactions; customers want digital payment options. According to McKinsey & Company's *2021 Digital Payments Consumer Survey*, in 2021, 82 percent of Americans used a digital payment channel – defined to include browser-based or in-app online purchases, in-store checkout using a mobile phone and/or QR code, and person-to-person payments compared to 78 percent in 2020, and 72 percent five years ago.

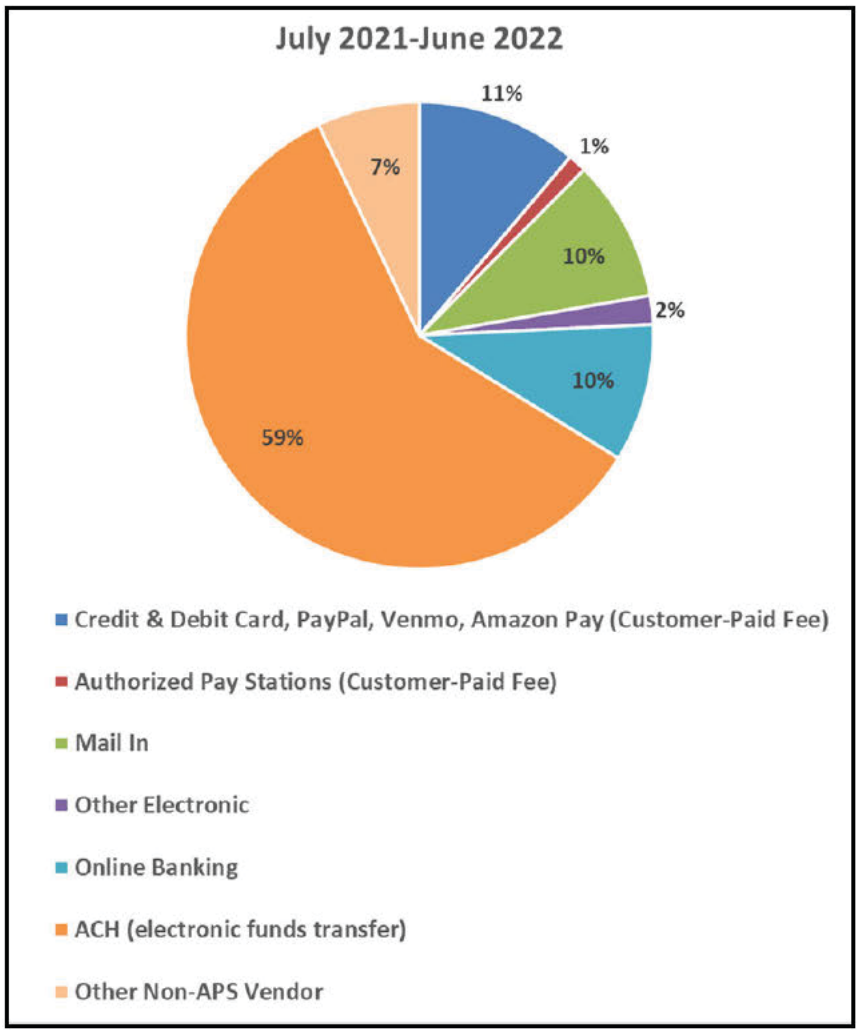
Excerpt from EEI Issue Brief, *Enhancing Customer Payment Approaches to Better Serve Residential and Small Business Customers*, May 2022 (Attachment MW-02DR).

This is consistent with the EEI year-over-year data that shows utility customers continue to shift from using paper payment checks to digital payment options as shown in Attachment MW-02DR.

Offering fee-free payment options improves customer satisfaction, aligns electric companies with the payment trends in other industries, and supports the growing number of APS customers who prefer the convenience of digital payments but are disgruntled about having to pay a fee when using a credit or debit card for payment. JDP and other studies show that customers highly value choice in digital payment options without fees. According to JDP 2021 best practice recommendations, payments absent of fees are important for a utility to improve their overall customer satisfaction. Today, APS customers expect to pay digitally. The majority of

payments to APS (82%) are being made digitally (*see* Figure 4). Approximately 12% of APS payments include vendor fees passed on directly to the Company's customers and some of APS's customers have expressed frustration and dissatisfaction about needing to pay a fee for payment methods they deem to be standard today.

Figure 4. Existing Percent of Payments to APS by Type, With or Without Fees



"Today, at least 31 investor-owned electric companies have regulatory approval for some type of cost recovery to support fee-free credit and debit card payments."[1] In the 2019 Rate Case, the Commission approved removal of credit card fees for limited-income customers. APS would like to address this customer pain point more broadly.

Q. RECOGNIZING THIS, WHAT IS APS PROPOSING WITH REGARD TO PAYMENT FEES?

A. APS proposes to eliminate payment fees for all APS network payment types and recover the associated vendor charges for individual transactions in base rates. Eliminating payment fees increases customer satisfaction by enhancing the ease of doing business with APS and aligns with today's standards.

Q. WHAT ARE THE IMPACTS OF THIS PROPOSAL?

A. During the Test Year, APS customers made approximately 1.5 million in-network digital payments that required fees. By eliminating payment fees, it allows all customers the opportunity to utilize the payment channel of their choice without an additional fee, making it easier for customers to do business with APS. With this transition, the Company expects that customers will complete 5.8 million payments with credit cards, debit cards, Amazon Pay, Venmo, PayPal, kiosks, and in-person retailers. With this increased volume, APS will be able to negotiate a reduced rate from today's fees, allowing more customers to pay through these desired digital channels for a lower cost per transaction. Ms. Hobbick discusses the additional $10.6 million needed annually to cover payment fees for customers.

[1] EEI Issue Brief, "Enhancing Customer Payment Approaches to Better Serve Residential and Small Business Customers" at 1 (May 2022).

VI. NEW OFF-PEAK HOLIDAYS

Q. IS APS PROPOSING NEW CUSTOMER HOLIDAYS?

A. Yes. APS is proposing two new additional off-peak holidays, to align with federal holidays, for residential customers on the Time-of-Use 4pm-7pm Weekdays and Time-of-Use 4pm-7pm Weekdays with Demand Charge rates, as well as customers on the Company's frozen Saver Choice Plus demand rate: Juneteenth, which is recognized on June 19 each year, and Indigenous Peoples' Day/Columbus Day, which is recognized on the second Monday in October. If approved, residential Time-of-Use customers will experience off-peak pricing on these days.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Drivers of J.D. Power (JDP) Customer Satisfaction

POWER QUALITY & RELIABILITY



- Supply electricity during very hot/very cold temps
- Provide quality electric power in terms of being free from spikes, drops, or surges
- Promptly restore power after an outage
- Keeping you informed about an outage/Provide accurate outage info (bus)
- Avoid brief interruptions of 5 minutes or less
- Avoid lengthy outages of more than 5 minutes

PRICE



- Total monthly cost of your electric service
- Fairness of pricing
- Ease of understanding your pricing options
- Efforts to help you manage your monthly usage
- Availability of pricing options that meet your needs

CORPORATE CITIZENSHIP



- Involvement in community
- Variety of energy efficiency programs offered
- Actions to take care of the environment
- Efforts to develop energy supply plans for the future

BILLING & PAYMENT



- Clarity of info. on your bill
- Ease of paying your bill
- Reasonableness of billing cycle
- Variety of methods to pay your bill

COMMUNICATIONS



- Efforts to communicate changes that might affect your account or service
- Communicating how to be safe around electricity
- Variety of communications used
- Creating messages that get your attention
- Efforts to get feedback from business customers (bus)
- Frequency of updates and notices of new developments (bus)
- Communications of topics/issues that are important to your business (bus)

CUSTOMER CARE



- Timeliness of resolving problem, question, request
- Ease of navigating website/ mobile app
- Appearance of website/app
- Clarity of the info provided
- Ease of using automated system
- Courtesy of the rep
- Promptness in speaking to a person
- Knowledge of the rep
- Rep's concern for needs
- Helpfulness of live chat rep

APS Residential Performance Within Large IOU Peer Set

	Quartile		Trend
	2021 Full Year	2022 Q3 YTD	
Overall Satisfaction (100%)	4th	2nd	↑
Power Quality & Reliability (25%)	3rd	2nd	↑
Price (20%)	4th	3rd	↑
Corporate Citizenship (17%)	4th	2nd	↑
Billing & Payment (17%)	4th	2nd	↑
Communications (12%)	4th	3rd	↑
Customer Care (9%)	4th	1st	↑
Digital (5.6%)	4th	1st	↑
Phone (2.6%)	2nd	1st	↑
In-Person (0.8%)	3rd	2nd	↑

APS Business Performance Compared to the Industry

	Quartile		Trend
	2021 Full Year	2022 Wave 1	
Overall Satisfaction (100%)	4th	1st	↑
Power Quality & Reliability (24%)	3rd	1st	↑
Price (19%)	4th	1st	↑
Billing & Payment (15%)	3rd	1st	↑
Corporate Citizenship (15%)	3rd	1st	↑
Customer Contact (14% or 22% with Contact)	3rd	2nd	↑
Digital (6.0%)	3rd	1st	↑
Phone (4.5%)	4th	2nd	↑
Proactive (3.5%)	3rd	3rd	↑
Communications (13%)	4th	1st	↑

Edison Electric INSTITUTE

Customer Solutions

Enhancing Customer Payment Approaches to Better Serve Residential and Small Business Customers

Issue Brief | May 2022

Prepared by: Adam Cooper, Lisa Wood, and Mike Shuster

JD Power and other studies show that customers highly value choice in payment options and that includes digital options. Year over year, data show that electric company customers continue to shift from using paper checks to digital payment options (e.g., website, app, text, electronic bank payment, credit cards, and debit cards, Apple Pay, and Google Pay). As customer preferences continue to change, the electric power industry increasingly is expanding its digital payment channels and accepted payment methods beyond credit and debit cards to include Apple Pay, Amazon Pay, PayPal, and Venmo to provide the payment options that customers want. As a result, electric companies are looking to put all payment options on a level playing field for customers by eliminating fees for certain payment options such as credit and debit card fees.[1] Today, at least 31 investor-owned electric companies have regulatory approval for some type of cost recovery to support fee-free credit and debit card payments.

Offering fee-free payment options improves customer satisfaction, aligns electric companies with payment trends of other industries, and supports the growing number of customers who prefer the convenience of digital payments but are disgruntled by having to pay a "fee" when using a credit or debit card for payment. For the roughly five percent of unbanked customers in the United States

[1] Joint Companies Testimony on Fee Free D.P.U. 20-91 Exhibit JC-Testimony-1 March 8, 2021, Page 20 of 49. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13232062

who rely on pre-paid cards that act like a debit or credit card to pay their bills, eliminating these fees provides direct benefits to this population.[2]

This issue brief discusses emerging digital payment trends, the benefits of expanding fee-free payment options, the types of customers using different payment options, and why creating a level playing field across payment options makes sense. It also provides an overview of the current regulatory treatment for digital payment options.

Digital Payment Trends: The New Normal

Today's residential and small business customers expect bill payment options from electric companies to be consistent with what they experience in other areas of their lives and business interactions; customers want digital payment options. According to McKinsey & Company's ***2021 Digital Payments Consumer Survey***, in 2021, 82 percent of Americans used a digital payment channel – defined to include browser-based or in-app online purchases, in-store checkout using a mobile phone and/or QR code, and person-to-person payments compared to 78 percent in 2020, and 72 percent five years ago.[3]

Figure 1 illustrates 2021 consumer survey results from Fiserv, an industry leader in payment card processing, on customer preferences for various bill pay options.[4] When asked how important it is to offer different ways to pay, 84 percent say paying by credit card is either a "must have" or "nice to have" and 79 percent say the same for debit card payments. For younger customers (millennials or Gen Z) the results are even more dramatic: 94 percent say payment by debit cards is a "must have" or "nice to have." Most customers say digital methods such as digital payment apps and mobile wallets are a "must have" or "nice to have."

Digital payments are the new normal. A 2019 study by The Federal Reserve Bank of Boston showed that growth in the use of credit and debit-card transactions increased by almost **nine percent per year** on average between 2015 and 2018.[5] One example of this trend is the U.S. federal government, which is moving toward electronic payments and away from checks and

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[2] Federal Deposits Insurance Corporation. October 2020. "How America Banks: Household Use of Banking and Financial Services." https://www.fdic.gov/analysis/household-survey/

[3] McKinsey & Company. Oct 2021. "New Trends in US Consumer Digital Payments." https://www.mckinsey.com/industries/financial-services/our-insights/banking-matters/new-trends-in-us-consumer-digital-payments

[4] Fiserv. Feb 2021. "Consumer Payments." https://www.fiserv.com/content/dam/fiserv-ent/final-files/graphics/infographics/EE_Consumer_Payments_Executive_Summary_0221.pdf

[5] Board of Governors of the Federal Reserve System. Dec 2019. "The 2019 Federal Reserve Payments Study". https://www.federalreserve.gov/paymentsystems/2019-December-The-Federal-Reserve-Payments-Study.htm

DIRECT TESTIMONY OF ANDREW COOPER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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ATTACHMENT LIST

Moody's Investors Service, *Regulated Electric & Gas Utilities*, Rating Methodology (June 23, 2017) ..... Attachment AC-01DR
S&P Global, *Key Credit Factors for Regulated Utility Industry,* Ratings (November 19, 2013) ..... Attachment AC-02DR
Clean Energy Proxy Matrix ..... Attachment AC-03DR

DIRECT TESTIMONY OF ANDREW COOPER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Andrew Cooper. I am the Senior Vice President and Chief Financial Officer for Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West Capital Corporation (Pinnacle West). As the Chief Financial Officer, I have oversight and responsibility for the accounting, finance, tax, and treasury functions of the Company and Pinnacle West. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Arts degree in government from Harvard College and a Juris Doctor degree from Harvard Law School. I joined APS in June 2020 as Vice President and Treasurer and took on my current role in May 2022. Prior to APS, I was Director of Corporate Finance at Consolidated Edison Company of New York, a regulated electric, gas and steam utility serving metropolitan New York City, where I previously oversaw all external financing activities for the company beginning in 2017. I began my career with more than 13 years in the banking sector, principally supporting clients in the regulated utility industry.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. No, but I have provided written testimony for the Federal Energy Regulatory Commission (FERC).

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to explain how customers of regulated utilities benefit from a financially stable utility, while also describing the Company's

current financial condition and its importance to Arizona. In addition, I provide testimony on the Company's Fair Value Increment proposal, discuss some financial implications of APS's planned retirements of coal-fired resources, and share information on a suggested clean energy proxy group for the Company and its relationship to APS's proposed return on equity (ROE).

II. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. By seeking new rates prior to the end of 2023, APS aims to achieve a number of customer-centric goals critical to delivering safe, reliable, and clean electricity. These include ensuring APS can build and maintain resilient infrastructure; supplying customers with cleaner and more balanced sources of energy; and improving the customer experience. Achieving these goals affordably for customers requires a foundation of financial stability.

In my testimony I explain how customers and investors both benefit when a utility has the financial resources to fund the provision of service under a broad range of financial circumstances and macroeconomic environments. This includes not only maintaining and improving existing infrastructure but also investing in clean and advanced technologies designed to meet the diversifying needs of APS's growing customer base. These advanced-technology, clean-resource investments are not only a high-value and cost-effective means to provide service to customers, but they also leverage both capital market preferences for more sustainable investing and recently expanded federal tax credits under the 2022 Inflation Reduction Act, both of which I describe in further detail within my testimony.

Cost effectively meeting the needs of APS's customers requires a balance between APS's access to capital markets and the Arizona regulatory environment. In this

respect, I discuss how credit ratings and investor confidence in a financially stable utility company have a direct impact on how much customers pay for electricity. Additionally, I will describe how establishing the opportunity to earn a fair and reasonable ROE and reducing regulatory lag on infrastructure investment benefit customers by supporting the development of clean, balanced, and resilient infrastructure.

III. THE COMPANY'S FINANCIAL HEALTH AND ITS IMPORTANCE TO ARIZONA

Q. PLEASE CHARACTERIZE THE COMPANY'S CURRENT FINANCIAL CONDITION.

A. APS expects its earned returns to continue to deteriorate in 2022 and beyond. In fact, APS has reported a significant drop in earnings in 2022 compared to 2021.

APS is focused on cost management and has implemented numerous cost savings to try to offset increased costs. However, the significant level of investment in the electric system necessary to improve and replace aging infrastructure, as well as meet the evolving needs of APS's customers and the economic growth of APS's service territory, cannot simply be offset by cost cutting measures alone. APS has no choice but to seek additional rate recovery to sustain the level of investment required to meet the growing needs of its customers.

All three credit rating agencies that rate APS's debt maintain a "negative" outlook on the Company's credit rating. In addition, APS's recent credit rating downgrades have placed upward pressure on APS's cost of short-term debt and its embedded cost of long-term debt, as new long-term debt securities will need to be issued at higher interest rates, which in turn will result in higher cost of debt going forward. Particularly in the current environment of financial market volatility and rising

interest rates, weaker credit ratings will have a more severe impact on cost. Notwithstanding the Company's efforts to mitigate these impacts, given the long-lived assets central to APS investment and the need to finance such assets with long-term bond issuances, the effect of credit downgrades on these transactions would likely result in long-term impacts to customers from higher debt costs that would be locked in for a generation. Any further downgrades that may come from continued pressure on returns and an increasingly risky regulatory environment would only exacerbate these problems.

The degradation of Pinnacle West market value has also resulted in an increase to the Company's cost of equity. During 2021, Pinnacle West common stock underperformed the Dow Jones Utility Index by more than 25%. In fact, over the last three years, Pinnacle West has underperformed the Dow Jones Utility Index by more than 50%. Lost equity value with the results of the last rate case also reduces operating cash flows requiring more borrowing at higher costs in order to meet the required investment to provide reliable and safe service to customers.

Q. HOW WOULD CONTINUED DEGRADATION TO THE REASONABLE OPPORTUNITY TO EARN ALLOWED RETURNS IMPACT CUSTOMERS?

A. Any further reduction in the Company's credit ratings would have a material and negative financial impact on the Company's cost of capital, and by extension, its customers. APS plans to invest significant capital over the next several years, and as described by APS witness Dr. Roger Morin, any further degradation of APS's credit would result in substantially higher costs to customers over the long term. For example, as described by Dr. Morin, investing $7.5 billion in capital over the next five years with an associated issuance of debt of $3.6 billion at a lower credit rating would increase costs to customers by $216 million. Moreover, market

volatility – such as financial markets are currently experiencing – can incrementally impact the embedded cost of long-term debt, potentially further increasing costs to customers. These potential cost increases can be avoided through an improved positive regulatory environment, which will enhance APS's ability to maneuver through market volatility and may also help to improve APS's credit ratings, which would result in meaningful savings to customers over the long term.

IV. IMPORTANCE OF A FINANCIALLY STABLE UTILITY FOR CUSTOMERS

Q. WHAT IS MEANT BY A "FINANCIALLY STABLE" UTILITY?

A. A financially stable utility is one that can attract both debt and equity financial resources within capital markets on terms favorable to APS's customers under a broad range of economic conditions. This requires strong investment-grade bond ratings and the ability to consistently earn an equity return that at least equals the marginal cost of capital.

Q. IS IT IN CUSTOMERS' BEST INTEREST TO HAVE A FINANCIALLY STABLE UTILITY?

A. Yes. Customers expect reliable and safe electricity to be available on demand and they expect rates to be affordable. For utilities to meet these needs cost-effectively, they must have access to external sources of financing on reasonable terms, from debt (bondholders and bank lenders) and equity (shareholders) capital. Both debt and equity capital are necessary sources to fund utility investment.

Q. HOW IS UTILITY RISK REFLECTED IN CUSTOMER COST?

A. One of the costs included in the revenue requirement is the cost of capital. The cost of capital is set in competitive financial markets and reflects the potential risk to investors. One of the risks investors assess, regulatory risk, increases with regulatory decisions that do not effectively balance the interests of customers and investors, and impacts how investors perceive the risk level of their investment in

the utility. When regulatory risk increases, credit rating agencies are likely to downgrade the credit of a utility and investors devalue an investment in that utility, which then corresponds to higher interest rates charged by investors on newly issued debt securities. Higher investor risk and lower credit ratings will also lead to a lower stock price and consequently a higher cost of equity. APS's cost of capital witness, Dr. Morin, describes how the cost of capital is determined for rate making purposes and proposes a fair cost of capital.

Q. DO THE PERCEIVED SHORT-TERM BENEFITS OF A LOWER AUTHORIZED RETURN OUTWEIGH THE LONG-TERM HIGHER COST TO CUSTOMERS?

A. No, any such perceived benefits do not outweigh the costs. While a decision by a regulator to award a return that is below the utility's true cost of capital may reduce the utility's revenue requirement in the short-term, over the long-term customers pay more due to the higher cost to finance investments that the utility must make to meet customer demands. In practical terms, this means the costs to finance and invest in critical long-lived infrastructure—such as power lines, substations, switchyards, and generation facilities—will only increase costs to customers in exchange for a short-term reduced revenue requirement. Moreover, any perceived short-term benefit is unsustainable as the chilling effect on investors creates a feedback loop of higher capital cost and reduced market access, which impairs a utility's ability to make cost effective investments required to keep up with customer needs. Conversely, the benefit of permitting a fair opportunity to earn sufficient returns to attract investment enhances the ability of a utility to provide reliable and affordable service to its customers and ensure a balanced energy supply.

Q. HOW DO INVESTORS ASSESS REGULATORY RISK?

A. Investors have a choice among competing investments, and they make their selections by weighing risks versus expected returns. One of the most significant types of risk to utility investors is regulatory risk. Utility regulation is a vital component of the electric industry and must fairly balance the needs of customers, the utility, and investors. Utility investors value the three closely related concepts of certainty, stability, and predictability. A regulatory environment that comports with these concepts is often referred to as a healthy regulatory environment. Regulatory risk is the risk that regulatory actions will jeopardize the utility's opportunity to recover its costs and earn its allowed rate of return on its shareholders' invested capital due to changes in laws or regulations (or changes in how those laws or regulations are implemented or enforced), which materially impacts the utility company by increasing costs and/or reducing the attractiveness of an investment.

Q. WHAT TYPES OF INVESTMENT CRITERIA MATTER TO APS'S INVESTORS?

A. APS's customers benefit from stable, long-term investors willing to keep their capital in Arizona. Such investors are attracted to predictable, stable, consistent regulatory environments. APS competes for capital in a global securities market and particularly against other long-term stable investments, such as other North American utilities. Investors in APS (both equity investors through their investment in the stock of APS's parent company Pinnacle West, and debt investors directly in APS's bonds), principally invest through large investment management companies. However, these investment managers are not the ultimate investors in APS. These investment managers allocate capital on behalf of the many individual investors that are seeking the stable and predictable return typically offered by North American utilities. These individual investors participate in utility

investments through their public and private employer pension funds, 401(k) accounts, life and disability insurance investments premiums, and mutual and exchange-traded fund investments. By way of example, at any given time, multiple U.S. states have their public employee civil service, teacher and law enforcement pensions invested in Pinnacle West stock and APS bonds. Beyond these investment managers representing the interests of their pensioner and individual investor participants, approximately 12% of Pinnacle West's common stock is held directly by individual investors seeking stable returns, particularly the predictability of dividend payments critical to retirees living on fixed incomes. These long-term investors, who have the lowest relative risk tolerance among investor classes, also in turn offer capital to utilities on the most favorable relative terms, ensuring the lowest cost to customers.

Q. HAS APS'S INVESTOR BASE CHANGED RECENTLY?

A. Yes. During the fiscal quarter in which the Commission decided the 2019 Rate Case, a number of long-term investors sold their positions in Pinnacle West stock, which not only lowered the stock price, increasing the Company's cost of capital, but also resulted in the exit of many of the stable, long-term shareholders that are the preferred investors for utilities and their customers. The message implicit in the exit of these long-term shareholders was that their risk analysis indicated the financial impact of regulation in Arizona would continue to reduce the value of an investment in Pinnacle West (stock price down 25% between the time APS filed the 2019 Rate Case and year-end 2021) such that they should not continue to hold the investment. One example is the Virginia Retirement System (VRS), which invests the pensions of more than 750,000 Virginia teachers, municipal and state employees and law enforcement personnel. VRS had been an investor in Pinnacle West's stock for many years and has maintained substantial shareholdings of between 250,000 and 500,000 shares consistently for the last decade. They sold

their total 323,000 Pinnacle West shares entirely during the fiscal quarter in which the 2019 Rate Case was decided.

Q. PLEASE DESCRIBE CIRCUMSTANCES THAT MAY HEIGHTEN THE RISK PROFILE OF A UTILITY AND THUS INCREASE COSTS TO CUSTOMERS.

A. Utility risk is at its highest when the predictability of a utility's investors earning a fair return on their investment is threatened. This can occur when an ROE is authorized that is below investor return requirements, where there is a lack of contemporaneous regulatory adjustment mechanisms to permit a fair opportunity for the utility to earn the authorized returns, where regulatory lag creates a gap between investment and a fair opportunity to earn the allowed return, and in other situations of regulatory or political uncertainty. Because these elements of regulatory recovery are the principal risks to utility investors, regulatory risk is central to the criteria used by the two primary credit rating agencies providing credit ratings to utilities. As reflected in Moody's Investors Service, *Regulated Electric & Gas Utilities*, Rating Methodology, Attachment AC-01DR, regulatory criteria comprise approximately 50% of Moody's rating scorecard factors. Similarly, reflected in S&P Global, *Key Credit Factors for Regulated Utility Industry,* Ratings, Attachment AC-02DR, S&P provides data and heat maps that indicate that 60% of its credit rating criteria is centered on predictable utility regulation.

Increased regulatory risk and regulatory lag reduce the opportunity to earn a fair return, which causes poor credit quality, lower credit ratings, higher interest costs, and a higher cost of equity. Once a utility is downgraded, it typically takes substantially longer for a utility to recover its credit rating and financial health than it does for that credit rating to decline. This is because of the credit rating agencies'

and debt investors' asymmetrical orientation toward risk – their investment yields only a fixed return of interest and principal and no additional upside to their return. As risk rises, the credit rating agencies apply elevated criteria when considering future credit upgrades. This process ensures investors are protected but has the effect of locking in a higher cost of capital for customers over a sustained period. For example, when the credit of APS was last at its weakest, it took a full eight years and regulatory support to bring the rating from BBB- (the next rating above "junk" credit) to the A- rating.

Q. ARE THESE INCREASED COSTS OF CAPITAL IMPACTED BY CAPITAL MARKET CONDITIONS?

A. Yes, capital market conditions are closely tied to credit quality in impacting utility risk. Quantifiable differences in credit quality are less impactful when capital markets are stable, and the gap between credit quality and cost, as well as real challenges to market access, are more readily observable during times of market volatility. When capital market access is diminished or severely restricted, such as the 2008 global financial crisis or early 2020 when the COVID-19 pandemic began, the borrowing cost gap between high credit quality companies and lower credit quality companies increases substantially. As the current period of capital market volatility resulting from inflationary price levels, Federal Reserve (Fed) policies intended to combat inflation, and geopolitical instability in Europe and Asia continues, the risk of higher cost remains elevated.

Q. HOW DOES THE CURRENT ENVIRONMENT OF INCREASING INTEREST RATES IMPACT THE COST AT WHICH UTILITIES ACCESS CAPITAL FROM INVESTORS?

A. In light of record levels of inflation, the Fed has implemented measures to attempt to curb inflation such as raising interest rates. Fed action to date and the market's anticipation of continued aggressive Fed action has impacted interest rates, with

the 10-year Treasury yield increasing by 135% year-to-date at September 30, 2022. The large capital investments that utilities like APS need to make and the need to borrow funds from the capital markets to do so, coupled with the market volatility described above, higher market risk and higher rates, all ultimately lead to higher borrowing costs for the utility and higher rates for the utility's customers. Market volatility and higher interest rates are factors outside the control of a utility and its regulator and can affect the utility's ability to keep customer rates affordable, especially when coupled with regulatory risks.

Q. HAS APS TAKEN ACTION TO ANTICIPATE AND MITIGATE THE IMPACT OF RISING INTEREST RATES?

A. Yes, APS actively monitors the capital markets and macroeconomic conditions and maintains up-to-date borrowing authorizations from the Commission in order to ensure it achieves the lowest possible cost of financing for APS's customers. In fact, APS's embedded cost of debt was 4.1% in the prior rate case. However, although the aggressiveness of Fed action and current market volatility was not well-anticipated by the market, APS took proactive measures to benefit from historically low interest rates to the benefit of APS's customers during both 2020 and 2021 and reduced the Company's embedded cost of debt to 3.85% in this case, a full 25 basis points below APS's prior embedded cost of debt. On a portfolio of over $6 billion of long-term debt, this reduction provides a substantial benefit to customers. In addition, the Company has increased its debt leverage, reducing APS's common equity capital from 54.7% to 51.9%, resulting in meaningful savings to customers.

While a portion of this benefit was achieved through the natural retirement of debt taken on in higher interest rate environments and when APS's credit rating was

lower, the Company also worked actively to reduce its debt cost to customers. Three activities exemplify this effort:

- In 2021, the Company enlarged the planned size of the bond offering issued in an effort to pre-fund 2022 capital investment needs, seeking to raise as much as $500 million instead of the $400 million that had originally been planned. The Company was able to raise $450 million, at a cost to customers of 2.2% over ten years, the lowest 10-year bond coupon in APS's portfolio. The inability to raise, at the same interest rate, the last $50 million sought was likely due to investor concerns related to the 2019 APS Rate Case.

- In 2020, the Company proactively optionally redeemed $105 million of bonds carrying an interest rate of 4.7% and replaced them with bonds that not only extended their maturity by an additional five years, which reduced refinancing risk to customers, but priced at a yield of 1.7%, a full 3% lower cost to customers than the bonds they replaced.

- The Company issued "Green Bonds" for a portion of its debt issuance in 2020, highlighting with investors APS's renewable energy investments. Bondholder interest in the offering, consistent with the ESG phenomenon I describe later in this testimony, exceeded the $400 million issuance size by three-fold, and as a result of those supply-demand dynamics APS was able to issue 30-year bonds at a very low cost of 2.65%, which was 0.70% lower than 30-year bonds the Company had issued just four months earlier.

Q. ARE AUTHORIZED ROE ISSUES IMPORTANT TO INVESTOR RISK EVALUATIONS, CREDIT RATINGS, AND THUS, TO APS'S CUSTOMERS?

A. Absolutely. APS's customers expect, and the Company is committed to providing, safe, reliable, and clean electricity. A reasonable ROE and a fair opportunity to earn that rate of return for APS—one that considers the relative risks associated with the Company's business—is a critical component of delivering on that expectation and commitment. In fact, investors assess authorized ROE when evaluating their willingness to provide capital to utilities. Investors also consider the utility's ability—through the regulatory structure afforded to the utility—to earn the authorized ROE.

The lack of a competitive ROE aligned with risk and a fair opportunity to earn that ROE results in reduced cash flow available to reinvest in its infrastructure for the benefit of customers which ultimately results in potentially degraded quality of service and, over the longer term, higher electricity rates for customers. With a reasonable ROE, though, APS can attract capital at a more cost effective rate than a financially weaker utility. Customers, not just investors, benefit by having a financially stable utility that has the earnings and cash flow sufficient to attract equity and debt on reasonable terms and, when necessary, the financial strength to wait for financial markets to stabilize before issuing long-term securities. This translates into lower rates for customers and, ultimately, better quality of electricity service.

V. FINANCIAL IMPLICATIONS OF THE COMPANY'S CLEAN ENERGY COMMITMENT

Q. WITH RESPECT TO APS'S REMAINING COAL-FIRED GENERATION ASSETS, WHAT VALUE DO THEY OFFER TO CUSTOMERS?

A. The Company's coal-fired generation assets ensure resource adequacy and reliable service for APS's customers at affordable prices in the significantly constrained western wholesale market. As described by APS witness Justin Joiner, the Company has carefully considered planned retirement dates to ensure that the replacement resources can provide a high level of reliability so that APS's customers' summertime peak loads are met while maintaining affordable electric service for customers. APS's clean energy commitment entails adding significant amounts of renewable generation and energy storage, and ending coal generation by 2031.

Q. FOR ANY UNRECOVERED BOOK VALUES THAT MIGHT REMAIN AFTER THESE ASSETS RETIRE, WHAT COST RECOVERY OPTIONS ARE AVAILABLE TO UTILITY COMPANIES LIKE APS?

A. The Company may have undepreciated book value remaining in connection with these assets upon their retirement. To address the concern of unrecovered book value at the planned retirement date for these assets, APS has a few options, including: (1) accelerating depreciation in the near term to either minimize or eliminate the remaining unrecovered book value by the retirement date in 2031, (2) amortizing the remaining book value through a regulatory asset over a set period of time, and/or (3) utilizing a financing tool such as securitization to recover the remaining book value and enable recycling of capital into replacement resources.

Each of these strategies presents unique challenges as well as benefits that must be considered. APS is continuing to assess these options, specifically including how

securitization could be accomplished in Arizona, given the complex array of legal, regulatory, legislative, and financing issues involved.

Q. WHAT ARE THE FINANCIAL MARKET IMPLICATIONS OF THE COMPANY'S CLEAN ENERGY COMMITMENT?

A. Institutional long-term investors are increasingly focused on the sustainability of their investments and are actively shifting their investment dollars towards companies that are focused on environment, social, and governance (ESG) criteria. ESG investing emphasizes direct consideration of ESG factors in the investment decision making process because investors view heightened financial risk associated with these factors. In particular, among the investors and lenders with the most significant impact on utility company access to capital, ESG considerations now play a significant role in their capital investment decision making. As the Company competes for capital access against other electric utility companies, APS does not anticipate diminishment of these considerations.

For utilities, most of the ESG scrutiny has fallen on the environmental factor, specifically carbon dioxide and other greenhouse gases. Investors are increasingly expecting utilities to decarbonize and invest in more sustainable generation resources, such as renewable generation and other non-carbon emitting resources. Many of Pinnacle West's largest shareholders are focused on ESG investing including large asset managers such as Vanguard, Blackrock and State Street. The credit rating agencies also continually measure and evaluate ESG metrics. In addition, lending banks that also provide capital to APS have developed ESG standards that, among other mandates, have built carbon reduction targets into their lending standards. An announcement in October 2020 by JPMorgan Chase, the largest bank in the United States, stated that the bank will use carbon-emission intensity targets for the electric utility sector in making financing determinations.

Q. WHAT ARE THE IMPLICATIONS OF THE FOCUS ON ESG FOR UTILITY CUSTOMERS?

A. With ESG considerations becoming important to lenders and investors, there are several implications of the enhanced visibility of these metrics for customers. First, the cost of capital will likely rise over time for companies and industries that do not make progress on ESG issues, especially the environmental factor. A second implication is that investors appear to have a preference for utilities that invest in non-carbon emitting energy resources to facilitate the transition to clean energy. To the extent that investors do not see APS execute on its clean energy commitment, the Company's investment risk profile may increase, raising costs to access capital and increasing customer rates.

Q. AS REQUESTED IN CHAIRWOMAN MÁRQUEZ PETERSON'S JUNE 2, 2022 LETTER, HAS APS DEVELOPED A PROPOSED CLEAN ENERGY PROXY GROUP?

A. Yes. Attached to my testimony as Attachment AC-03DR, Clean Energy Proxy Matrix, APS has prepared an extensive table that compiles information on the "essential factors" associated with a variety of North American Investor-Owned Utilities (IOUs), which were identified in Attachment C to Chairwoman Márquez Peterson's June 2, 2022 letter, along with a list of additional potentially relevant factors to the current electric utility industry clean energy transition. As it relates to APS's clean energy commitment, the information in Attachment AC-03DR offers a number of helpful points of comparison.

Q. WHAT CONCLUSIONS, IF ANY, CAN BE DRAWN FROM THE CLEAN ENERGY PROXY GROUP TABLE AS IT RELATES TO THE BUSINESS RISKS FACING APS?

A. The information within Attachment AC-03DR demonstrates that APS is not unique in making a commitment toward a clean energy investment strategy. Of the 79

North American IOUs surveyed and documented in Attachment AC-03DR, 96% have made some form of clean energy commitment similar to APS. As further shown within Attachment AC-03DR, the overwhelming trend for these companies is similar to APS—retire legacy coal generation and replace that generation capacity with clean resources. As such, from a risk perspective, APS's clean energy commitment does not expose the Company to any greater or less risk than its peer IOUs across North America. Consistent with testimony from APS's ROE expert, Dr. Morin, Attachment AC-03DR provides further support for the proposition that traditional investor evaluations of risk already consider clean energy commitments of IOUs.

Q. HAS APS DEVELOPED PROJECTIONS OR ESTIMATES OF NECESSARY CAPITAL INVESTMENT NEEDED BETWEEN NOW AND 2035 TO SUPPORT THE COMPANY'S CLEAN ENERGY COMMITMENT?

A. In connection with APS's public Form 10K SEC disclosures, the Company has made available the current forecast of capital investment projections through 2024, including for clean energy related investments. This level of capital spending includes investments in renewable and energy storage systems of $230 million in 2022, $210 million in 2023, increasing to $450 million in 2024. The level of clean energy related investment in 2024 is illustrative of the annual level of investment that is likely necessary to serve customers. That said, given the high likelihood of changed circumstances as to APS and the ever-changing capital and energy market dynamics in which the Company conducts business, specific projections of annual capital spending beyond 2024 are unlikely to be accurate or useful in assessing APS's financial ability to execute its clean energy commitment. Mr. Joiner further discusses resource needs and APS's competitive procurement process.

Q. COULD THE 2022 INFLATION REDUCTION ACT PROVIDE FINANCIAL RELIEF FOR APS AND ITS CUSTOMERS?

A. Yes. The Inflation Reduction Act of 2022 (2022 IRA) was signed into law on August 16, 2022. The 2022 IRA represents the most substantial federal investment in clean energy and expands the availability of tax credits for investments in clean energy generation technologies and energy storage. The 2022 IRA creates an opportunity through tax credits to reduce the cost of investment in renewable and energy storage technology, which can be passed on to customers. Key provisions that are relevant to APS's clean energy commitment include (i) an extension of tax credits for solar and wind generation, including a new option for solar investments to claim a Production Tax Credit (PTC) in lieu of the Investment Tax Credit (ITC) beginning in 2022; (ii) expansion of the ITC to cover stand-alone energy storage technology beginning in 2023, and (iii) introduction of a new PTC for nuclear energy produced by existing nuclear energy plants, available from 2024 through 2032. The Internal Revenue Service and the United States Treasury are expected to issue regulations and other guidance which will provide additional details and clarification on how the Company may be able to claim each of these credits. With respect to the nuclear PTC specifically, additional United States Treasury guidance is necessary to determine the amount of credits that APS may ultimately be able to claim.

Q. WHAT OTHER OPPORTUNITIES ARE AVAILABLE FOR CUSTOMERS UNDER THE 2022 IRA?

A. As with the PTC for generation from existing nuclear power plants, there are numerous facets of the 2022 IRA that still require interpretation and regulatory development by the United States Government prior to them being available. APS continues to evaluate the 2022 IRA and monitor activity by United States.

Government agencies responsible for implementing its provisions to determine how best to leverage the 2022 IRA for the benefit of customers.

Q. HAS THE COMPANY INCLUDED ANY OF THESE TAX BENEFITS IN ITS REVENUE REQUIREMENT?

A. Yes. As described by APS witness Elizabeth Blankenship, ITC benefits have been included in post-Test Year plant (PTYP) for the AZ Sun Battery investments to reduce the total cost of these assets by $77.3 million. In addition, the Company is proposing to include the estimated PTC benefit of the Agave Solar facility, which is also in PTYP, in the expanded REAC as such PTCs are earned (i.e., as energy is produced which generates a PTC). This will appropriately align the cost recovery of these assets with the tax benefits that these assets are generating. These PTCs will be subject to true-up for any difference between the expected PTC included in the REAC, and the actual PTC claimed and sustained on the income tax return.

VI. IMPORTANCE OF REGULATORY ADJUSTMENT MECHANISMS

Q. HOW DO DEBT AND EQUITY INVESTORS AS WELL AS CREDIT RATING AGENCIES VIEW REGULATORY ADJUSTMENT MECHANISMS?

A. Investors, lenders, and credit rating agencies favorably recognize the benefits of regulatory adjustment mechanisms and their contribution to predictable and timely cash flows. Specifically, these entities acknowledge the importance of adjustor mechanisms in reducing regulatory lag and supporting credit quality, which in turn reduces regulatory risk and costs to customers. They understand that APS's existing and proposed regulatory adjustment mechanisms are consistent with similar mechanisms across the industry and are considered fairly standard regulatory adjustment mechanisms.

Q. WHAT BENEFITS DO THE COMPANY'S REGULATORY ADJUSTMENT MECHANISMS PROVIDE?

A. Regulatory adjustment mechanisms provide benefits to both customers and the Company. Customers benefit from reduced frequency of rate cases, rate gradualism, the matching of costs and benefits, the ability to pass savings or benefits to customers faster, and the promotion of public policy goals that support customer programs such as energy efficiency, demand response, access to renewable energy and the like. There are other benefits that inure both to APS and its customers. For example, adjustors reduce regulatory lag, provide increased certainty of cost recovery, and offer cash flow benefits. These benefits support the financial stability of the utility by providing increased predictability of rate recovery—which improves credit ratings and lowers borrowing costs—both of which help keep customer rates more affordable.

Q. PLEASE PROVIDE A SPECIFIC EXAMPLE OF HOW APS'S ADJUSTOR MECHANISMS BENEFIT CUSTOMERS?

A. The Company's existing and proposed regulatory adjustment mechanisms serve to reduce regulatory lag as well as match the benefits that customers receive from the Company's investments in renewable technologies and demand side management—through long term fuel savings and reliable service—with the costs incurred to achieve those benefits. For example, the Company's proposed modification to the Renewable Energy Adjustment Charge (REAC) will provide for the recovery of carrying charges on new renewable and energy storage investments, including passing along any associated tax benefits related to those assets resulting in reduced costs for customers. Likewise, the Power Supply Adjustor (PSA) allows customers to experience savings on fuel and purchased power costs when new renewable resources and energy storage equipment goes into service, rather than waiting for a rate case. The PSA, which is a standard

mechanism across the utility industry, is central to the Company's liquidity and helps reduce credit risk related to Power Purchase Agreements (PPA), reducing financing costs for customers.

Q. HOW IS THE PSA VIEWED BY CREDIT RATING AGENCIES, ESPECIALLY AS IT RELATES TO POWER PURCHASE AGREEMENTS?

A. Recovery of purchased power costs through the PSA mechanism is viewed positively by credit rating agencies when considering the Company's credit rating and allows credit rating agencies to discount the imputed debt that is created by PPAs, when considering the Company's credit metrics. Absent such recovery mechanism, credit rating agencies would not treat these agreements as favorable, which would in turn increase the Company's cost of capital, negatively impacting customers through higher electricity rates.

Although PPAs are not considered long-term debt, such agreements have characteristics of debt, since the fixed payments, similar to interest payments, reduce financial flexibility and increase the risk of default for the utility. To the extent that the Company enters into PPAs to meet growing demand for electricity in Arizona, the equity capital provided by shareholders will also support the credit of the capital raised by the PPA provider. Because APS maintains the PSA mechanism for concurrent recovery of PPA costs, though, the degree of capital subsidization is minimized. So, while APS must always consider the equity capital support and the imputed debt from credit ratings agencies when determining whether to enter into a given PPA, the PSA mechanism mitigates the degree to which these financial impacts affect customers.

Q. HOW WOULD EARNING A RETURN ON POWER PURCHASE AGREEMENTS, AS CONTEMPLATED BY CHAIRWOMAN MÁRQUEZ PETERSON, IMPROVE THE FINANCIAL STABILITY OF APS?

A. Providing APS a return on PPAs would more appropriately match the costs related to the impact PPAs have on APS's cost of capital with the benefit realized by APS's customers through lower cost supply alternatives as the Company executes its integrated resource plan (IRP) over the next several years. The ability to earn a return on PPAs would be a creative approach to address the impacts that PPAs have related to imputed debt and the accounting lease treatment that these agreements often carry, which stress APS's balance sheet and which may lead to increased cost of capital impacting customers. PPAs are recovered dollar for dollar through the Company's PSA mechanism, where customers also realize the benefit of these agreements related to low-cost fuel alternatives.

Chairwoman Márquez Peterson references the approach used in Michigan, where utilities have the ability to recover a return on and of PPAs through a separate financial compensation mechanism. Assuming APS were able to earn a return on and of PPA costs through its PSA or similar mechanism, this would likely be viewed as credit positive and help to support the financial health of the Company, thereby benefiting APS's customers. In the absence of a concurrent cost recovery mechanism for both the return on and of PPA costs, however, these benefits would be lost and the Company's financial health would likely be diminished.

VII. FAIR VALUE INCREMENT REQUEST

Q. WHAT IS APS'S FAIR VALUE RATE OF RETURN?

A. Figure 1 below reflects APS's proposed rate of return on a fair value rate base (FVRB) of 4.92%, which is based on a fair value rate base of $16,584,454,000.

Figure 1. APS's Proposed Rate of Return on Fair Value Rate Base

(Dollars in Thousands)

	Amount	%	Cost Rate	Weighted Avg
Long-Term Debt	$ 5,054,982	30.48%	3.85%	1.17%
Common Equity	5,460,895	32.93%	10.25%	3.38%
FVRB Increment	6,068,577	36.59%	1.00%	0.37%
Total	**$ 16,584,454**	**100.00%**		**4.92%**

Q. HOW WAS THE FAIR VALUE RATE OF RETURN DETERMINED?

A. As described by APS witness Jamie Moe, the fair value rate of return is determined by applying the market return on equity (ROE) of 10.25% and cost of debt of 3.85% to the Company's original cost rate base (OCRB) based on the percent of equity and debt in the Company's proposed capital structure as well as a return of 1% on the "fair value increment" above the OCRB. The fair value rate of return is the sum of the weighted returns on each of the three components: (1) equity capital; (2) debt capital; and (3) the fair value increment. Each is weighted by the percentage in the FVRB.

Q. WHAT IS THE FAIR VALUE INCREMENT?

A. The fair value increment is the difference between the OCRB and FVRB. The fair value increment represents the appreciation in the value of assets to their current value. The sum of the OCRB and fair value increment is the total fair value of the utility's property.

Q. SHOULD A RETURN BE APPLIED TO THE FAIR VALUE INCREMENT?

A. Yes. The Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's property. To establish a just and reasonable revenue requirement, the Commission would need to assign an appropriate return on the fair value increment.

Q. IS THE APPLICATION OF A RETURN ON THE FAIR VALUE INCREMENT CONSISTENT WITH PRIOR COMMISSION CASES?

A. Yes. The Commission has authorized returns on the fair value increment in previous cases. In these cases, the Commission typically authorized a return on the fair value increment by utilizing the risk-free interest rate as a benchmark.[1]

Q. WHAT IS THE REAL RISK-FREE RATE?

A. The concept of real risk-free rates involves removing the rate of inflation from the nominal risk-free rate. The nominal risk-free rate is based on the yields of U.S. Treasury bonds, which are universally considered by investors to be risk-free investments.

Q. WHAT RATE OF RETURN SHOULD BE APPLIED TO THE FAIR VALUE INCREMENT IN THIS CASE?

A. As discussed and analyzed more comprehensively in Dr. Morin's testimony, the nominal risk-free rate is 3.7%, and the real risk-free rate is estimated to be 1%. In this case, APS is proposing a return on the fair value increment of 1%, which aligns to Dr. Morin's real risk-free rate. APS believes this proposal is both reasonable and consistent with previous Commission decisions.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[1] *See, e.g.,* Decision No. 70665 at 32-33 (Dec. 24, 2008).

JUNE 23, 2017

INFRASTRUCTURE

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RATING METHODOLOGY

Regulated Electric and Gas Utilities

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This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector. [1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4][5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

[2] Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

[3] Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

[4] We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

[5] A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in sixsections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprisedof sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

[6] For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

[7] Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historical and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$

[8] In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider

[6] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that

has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

[10] In certain circumstances, analysts may also apply specific adjustments.

[11] We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are up-

streamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[1310] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

[12] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[13] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[14] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

- Substantial diversity in cash flows from a variety of utility OpCos
- Meaningful dividends to HoldCo from unlevered utility OpCos
- Dependable, meaningful dividends to HoldCo from non-utility OpCos
- The group's investment program is primarily in strong utility businesses
- Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity

generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of

these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma capitalization/leverage

[15] See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based onlegislation that provides the utility a nearly absolute monopoly (see note 1_ within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make andrecover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
		Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
CFO pre-WC / Debt	15%								
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
		Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
CFO pre-WC - Dividends / Debt	10%								
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
		Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
Debt / Capitalization	7.5%								
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[1614] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

- Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo
- Differentiation of the regulatory frameworks of the various OpCos
- Specific ring-fencing provisions at particular OpCos
- Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets
- Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family
- The extent to which higher leverage at one entity increases default risk for other members of the family
- An entity's exposure to or insulation from an affiliate with high business risk
- Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility Holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, largerwaves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A longperiod of globally low interest rates, held down by monetary stimulus policies, has generally benefittedutilities, since reductions in allowed returns have been slower than reductions in incurred capital costs.Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult topredict is how regulators will respond when monetary stimulus reverses, and how well utilities will farewhen fixed income investors require higher interest rates and equity investors require higher total returnsand growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compressionof returns has been relatively steep in recent years. In Japan, the regulatory authorities are working throughthe challenges presented by the decision to shut down virtually all of the country's nuclear generationcapacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favoredgeneration sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordab lity to the general public. Singapore and Hong Kong have fairly well developedand supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea andThailand have been moving towards a more transparent regulatory framework. The Philippines is in theprocess of deregulating its power market, while Indian power utilities continue to grapple with structuralchallenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable,long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance

distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the

[17] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.
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securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility.

In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

November 19, 2013

(***Editor's Note:*** *We're republishing this article following our periodic review completed on June 5, 2018. See the "Revisions And Updates" section for details.)*

1. This article presents S&P Global Ratings' methodology and assumptions for Regulated Utilities. This article relates to "Corporate Methodology," Nov. 19, 2013 and "Principles Of Credit Ratings," Feb. 16, 2011.
2. This paragraph has been deleted.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," March 25, 2015).

SUMMARY OF THE CRITERIA

4. This article presents S&P Global Ratings criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of

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evaluating regulated utilities, specifically, the conditions to apply low, medial, and standard volatility tables. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

5. This paragraph has been deleted.

6. This paragraph has been deleted.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11. We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15. As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and

- Profitability.

19. In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.
20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.
22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.
23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:
24. Regulatory stability:
    - Transparency of the key components of the rate setting and how these are assessed
    - Predictability that lowers uncertainty for the utility and its stakeholders
    - Consistency in the regulatory framework over time
25. Tariff-setting procedures and design:
    - Recoverability of all operating and capital costs in full
    - Balance of the interests and concerns of all stakeholders affected
    - Incentives that are achievable and contained
26. Financial stability:
    - Timeliness of cost recovery to avoid cash flow volatility
    - Flexibility to allow for recovery of unexpected costs if they arise
    - Attractiveness of the framework to attract long-term capital
    - Capital support during construction to alleviate funding and cash flow pressure during periods

of heavy investments

27. Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)

Qualifier	What it means	Guidance
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments. and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's

management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.

- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e., extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance

requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;

- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,

- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates.

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments

in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio. The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a

dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.
- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the debt.
- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).
- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.
- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;
- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Dec. 16, 2014) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. For this reason, when determining if utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity, we use slightly lower thresholds:

- A ratio of sources to uses higher than 1.1x, compared with the standard 1.2x;
- Positive sources over uses even if forecast EBITDA declines by 10% (compared with a 15% decline for corporate issuers); and
- No covenant breach even if forecast EBITDA declines by 10% (compared with a 15% decline for corporate issuers).

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

APPENDIX--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or

negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state

ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

REVISIONS AND UPDATES

This article was originally published on Nov. 19, 2013. These criteria became effective on Nov. 19, 2013.

Changes introduced after original publication:

- Following our periodic review completed on June 17, 2016, we updated the contact information and criteria references and deleted paragraphs 2, 5, and 6, which were related to the initial publication of our criteria and no longer relevant.
- Following our periodic review completed on June 6, 2017, we updated the contact information and criteria references and clarified paragraphs 4 and 84.
- Following our periodic review completed on June 5, 2018, we updated the contact information and criteria references and renamed the "Revision History" section to "Revisions And Updates."

RELATED CRITERIA AND RESEARCH

Superseded Criteria

- Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting, Jan. 27, 2010
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2007

Related Criteria

- Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018

- Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Methodology: Jurisdiction Ranking Assessments, Jan. 21, 2016
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- Securitizing Stranded Costs, Jan. 18, 2001

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ARIZONA PUBLIC SERVICE COMPANY

CLEAN ENERGY PROXY MATRIX

The following matrix has been prepared in response to Chairwoman Márquez Peterson's letter of June 2, 2022 requesting information for a set of operating utilities that could provide the basis for a Clean Energy Proxy Group. The Chairwoman's letter can be found here: E000019523.pdf (azcc.gov).

The matrix provides operating, financial, and clean energy data for 80 operating utilities, including APS, that meet the Chairwoman's threshold criteria as listed in Attachment C of her letter. These utilities are investor-owned, located in the lower 48 contiguous states, and have annual operating revenues of $10 million or more. APS has added an additional threshold: all the utilities on the list are located in states that have not adopted full retail competition, as utilities without owned generation assets are not appropriate for proxy comparison purposes to the Company.

The matrix is presented in two sections: the first provides operating and financial data for each utility, and the second provides clean energy data for each utility. The list of utilities was developed from information gathered by the Edison Electric Institute (EEI) in the report *Profiles and Rankings of Investor-Owned Electric Companies* dated December 2021.

Below is a description of the data included in the matrix along with the sources from which the data was compiled.

Utility Identifying Data.

Column A: Operating utility name. For some utilities that have recently merged or have retained an earlier name, a "doing business as (DBA)" name is included to help identify the utility. *Data source(s): EEI.*

Column B: State. Lists the state(s) in which the operating utility provides electric service to ultimate retail customers. *Data source(s): EEI.*

Column C: Holding Company. Shows the operating utility's holding company, if any. *Data source(s): EEI.*

Operating and Financial Data.

Column D: Holding Company Included in Dr. Morin's Proxy Group. Identifies whether the operating utility is held by a company included in the proxy group used to prepare a reliable and statistically valid Discounted Cash Flow (DCF) cost of capital

model by APS witness Dr. Roger Morin, the Company's cost of equity expert. *Data source(s): Direct Testimony of Roger A. Morin on behalf of Arizona Public Service Company in Docket No. E-01345A-22-0144.*

Column E: RTO/ISO. Identifies the Regional Transmission Organization (RTO) or Independent System Operator (ISO) each utility is associated with, if any. *Data source(s): EEI, individual RTO and ISO websites, individual utility and holding company websites.*

Column F: Size of Service Territory. Provides the square miles of electric certificated service territory for the utility as a whole, including service territory in all states in which the utility operates. *Data source(s): EEI, individual utility and holding company websites.*

Column G: Transmission Pole Miles. Lists the number of pole miles for both wholly owned and jointly owned utility transmission lines. *Data source(s): Federal Energy Regulatory Commission (FERC) Form 1.*

Column H: Nuclear Plant Ownership and Operation. Identifies utilities that have an ownership stake in a currently operating nuclear generating station and those that are also responsible for operation and management of the resource. *Data source(s): Nuclear Energy Institute (NEI) website.*

Column I: Test Year Period. Shows the period (historical and/or forecasted) used to determine customer rates in each jurisdiction in which the utility operates. *Data source(s): S&P Global Market Intelligence (Regulatory Research Associates).*

Column J: Commissioner Selection Process. Lists the method by which Commissioners are determined in each jurisdiction the utility is regulated in. *Data source(s): S&P Global Market Intelligence (Regulatory Research Associates).*

Column K: Most Recent Electric Return on Equity (ROE) Approved by the Public Utility Commission (PUC). Provides the ROE most recently approved by each jurisdiction in which the utility operates, if made available. *Data source(s): S&P Global Market Intelligence (Regulatory Research Associates).*

Column L: Operating Utility Actual 2021 Year-End ROE. Identifies the actual achieved ROE for the utility as reported in SEC filings if available. This statistic is shown and identified as Return on Average Common Equity (ROACE) for some utilities. *Data source(s): S&P Global Market Intelligence (Regulatory Research Associates).*

Column M: Residential Customers Served at Year-End 2021. Provides the percentage of residential customers to total retail customers served for each jurisdiction in which the utility operates. *Data source(s): Energy Information Administration (EIA).*

Clean Energy Data.

Column N: Utility Clean/Renewable Electric Energy Commitment/Goal. Lists the operating utility's individual clean energy goal if different from the holding company goal. *Data source(s): Utility and Holding Company individual websites.*

Column O: Holding Company Clean/Renewable Electric Energy Commitment/Goal. Provides the holding company's clean energy goals. *Data source(s): Utility and Holding Company individual websites.*

Column P: State Clean/Renewable Energy Standard/Goal. Identifies goals adopted by the state through legislation or by the public utility commission through rulemakings for each state in which the utility operates. *Data source(s): Database of State Incentives for Renewables and Efficiency (DSIRE), EIA, individual jurisdictional commission websites, individual state websites.*

Column Q: Energy/Resource Mix. Provides energy or generation mix (as noted) for each utility as available. *Data source(s): EIA, individual utility websites, holding company websites.*

Column R: Fossil Capacity Planned for Retirement. Lists fossil generating units each utility currently plans to retire, including ownership percentages in jointly owned units, and the year in which retirement is expected to occur. *Data source(s): EIA, individual utility websites, holding company websites, S&P Global Market Intelligence.*

Column S: Securitization Enabled. Lists whether securitization has been authorized in each jurisdiction in which the utility operates. *Data source(s): S&P Global Market Intelligence*.

Column T: Net Energy Metering or RCP Policy. Identifies which utilities offer net metering or resource comparison proxy rate to customers with on-site distributed generation resources for each jurisdiction in which the utility operates. *Data source(s): EEI, individual utility websites.*

Column U: Installed Community Solar Capacity. Identifies any community solar projects associated with the operating utility. *Data source(s): National Renewable Energy Laboratory (NREL), individual utility websites.*

UTILITY OPERATING AND FINANCIAL STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Holding Company Included in Dr. Morin's Proxy Group	RTO/ISO	Size of Service Territory (sq miles)	Transmission Pole Miles	Nuclear Plant Ownership and Operation	Test Year Period	Commissioner Selection Process	Most Recent Electric ROE Approved by the PUC	Operating Utility Actual 2021 Year-End Return on Equity	Residential Customers Served Year-End 2021
(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*
AES Indiana (Indianapolis Power & Light)	IN	AES	No	MISO	527	863	No	Historical with Known and Measurable Changes	Appointed	9.99% (Settled)	9.44% (ROACE)	88.3%
Alabama Power	AL	Southern	Yes	None	20,119	10,763	Owner	Historical with Known and Measurable Changes	Elected	Not Calculated in Formula Rate	12.06%	86.1%
Ameren Missouri (Union Electric)	MO	Ameren	Yes	MISO	15,207	2,557	Owner and Operator	Historical	Appointed	Not Calculated in Settlement	9.38% (ROACE)	86.6%
Appalachian Power	VA, WV	American Electric Power (AEP)	Yes	PJM	18,552	6,428	No	VA: Historical WV: Historical	VA: Elected (by Legislature) WV: Appointed	VA: 9.20% WV: 9.75% (Settled)	7.76%	VA: 84.9% WV: 83.6%
Arizona Public Service	AZ	Pinnacle West	N/A	None	34,907	5,802	Owner and Operator	Historical	Elected	8.70%	9.7% (Jurisdictional)	89.5%
Avista Utilities	ID, WA	Avista Corp.	Yes	None	16,976	2,244	No	ID: Historical WA: Historical	ID: Appointed WA: Appointed	ID: 9.40% (Settled) WA: 9.40% (Settled)	7.07% (ROACE)	D: 86.6% WA: 89.7%
Black Hills Power	MT, SD, WY	Black Hills Corp.	Yes	None	1,532	772	No	MT: Historical SD: Historical WY: Historical	MT: Elected SD: Elected WY: Appointed	MT: 15.00% SD: Not disclosed in settlement WY: 9 90% (Settled)	10.90%	MT: 31.7% SD: 81.6% WY: 76.7%
Black Hills Colorado Electric Utility	CO	Black Hills Corp.	Yes	None	10,473	323	No	Historical or Forecasted	Appointed	9.37%	Not Reported	88.2%
Cheyenne Light Fuel & Power	WY	Black Hills Corp.	Yes	None	957	62	No	Historical	Appointed	9.90%	Not Reported	88.0%
CLECO Power	LA	Cleco Corp.	No	MISO	7,304	1,435	No	Historical	Elected	9.50% (Settled)	7.18% (ROACE)	85.2%
Consolidated Water Power	WI	Verso Minnesota Wisconsin	No	MISO	37	57	No	Forecast	Appointed	10.00%	Not Reported	80.5%
Consumers Energy	MI	CMS Energy Corp.	Yes	MISO	29,477	215	No	Forecast	Appointed	9.90%	9.75%	87.8%
Dahlberg Light & Power	WI	Dahlberg	No	MISO	892	Not Available	No	Forecast	Appointed	11.00%	Not Reported	89.3%
Dominion Energy Virginia (Virginia Electric Power)	NC, VA	Dominion Energy	Yes	PJM	12,894	6,742	Owner and Operator	NC: Historical VA: Historical	VA: Elected (by Legislature) NC: Appointed	NC: 9.75% (Settled) VA: 9.35% (Settled)	11.27% (ROACE)	NC: 85.0% VA: 89.7%
Dominion Energy South Carolina	SC	Dominion Energy	Yes	None	5,750	3,841	Owner and Operator	Historical	Elected (by Legislature)	9.50%	11.94%	86.1%
DTE Electric	MI	DTE Energy Co.	No	MISO	7,429	None	Owner and Operator	Forecast	Appointed	9.90%	10.21%	90.7%

UTILITY OPERATING AND FINANCIAL STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Holding Company Included in Dr. Morin's Proxy Group	RTO/ISO	Size of Service Territory (sq miles)	Transmission Pole Miles	Nuclear Plant Ownership and Operation	Test Year Period	Commissioner Selection Process	Most Recent Electric ROE Approved by the PUC	Operating Utility Actual 2021 Year-End Return on Equity	Residential Customers Served Year-End 2021
Duke Energy Carolinas	NC, SC	Duke Energy	Yes	None	24,801	8,278	Owner and Operator	NC: Historical SC: Historical	NC: Appointed SC: Elected (by Legislature)	NC: 9.60% (Settled) SC: 9.50%	11.72%	NC: 85 3% SC: 83.3%
Duke Energy Florida	FL	Duke Energy	Yes	None	7,160	4,393	No	Forecast	Appointed	9.85%	9 55%	88.5%
Duke Energy Indiana	IN	Duke Energy	Yes	MISO	5,451	5,286	No	Historical with Known and Measureable Changes	Appointed	9.70%	10.02%	87.6%
Duke Energy Kentucky	KY	Duke Energy	Yes	PJM	296	107	No	Historical	Appointed	9.25%	7.17%	89.1%
Duke Energy Progress	NC, SC	Duke Energy	Yes	None	28,314	6,292	Owner and Operator	NC: Historical SC: Historical	NC: Appointed SC: Elected (by Legislature)	NC: 9.60% (Settled) SC: 9.50%	11.23%	NC: 85 5% SC: 81.2%
El Paso Electric	NM, TX	El Paso Electric	No	None	7,675	1,849	Owner	NM: Historical with Known and Measurable Changes TX: Historical	NM: Elected TX: Appointed	NM: 9.00% TX: 9 35% (Settled)	Not Reported	NM: 88 3% TX: 88.7%
Entergy Arkansas	AR	Entergy Corp.	Yes	MISO	40,996	5,163	Owner and Operator	Historical with Known and Measurable Changes	AR: Appointed	AR: 9.65% Midpoint (Settled)	9.65% Midpoint (Settled)	AR: 82.6%
Entergy Louisiana	LA	Entergy Corp.	Yes	MISO	27,396	6,365	Owner and Operator	Historical	Elected	9.50% Midpoint (Settled)	8 36%	85.8%
Entergy Mississippi	MS	Entergy Corp.	Yes	MISO	6,632	3,251	No	Forecast	Elected	10.07% Midpoint (Settled)	9 50%	83.1%
Entergy New Orleans	LA	Entergy Corp.	Yes	MISO	105	161	No	Historical	Elected	9.35% Midpoint	5.11%	89.7%
Entergy Texas	TX	Entergy Corp.	Yes	MISO	17,984	3,129	No	Historical	Appointed	9.65% (Settled)	9 94%	87.5%
Evergy Kansas Central	KS	Evergy Inc.	Yes	SPP	7,468	3,722	No	Historical	Appointed	9.30% (Settled)	11.05%	85.8%
Evergy Kansas South	KS	Evergy Inc.	Yes	SPP	3,428	2,673	Owner	Historical	Appointed	9.30% (Settled)	Not Reported	87.0%
Evergy Metro	KS, MO	Evergy Inc.	Yes	SPP	4,897	1,874	Owner	KS: Historical MO: Historical	KS: Appointed MO: Appointed	KS: 9.30% (Settled) MO: 9.70% (Settled)	10.81%	KS: 88.1% MO: 88.6%
Evergy Missouri West	MO	Evergy Inc.	Yes	SPP	2,332	1,350	No	Historical	Appointed	9.70% (Settled)	Not Reported	87.8%
Florida Power & Light	FL	NextEra Energy	No	None	15,315	7,491	Owner and Operator	Forecast	Appointed	10.60%	10.27%	88.6%
Georgia Power	GA	Southern	Yes	None	17,406	12,441	Owner	Forecast	Elected	10.50%	11.39%	87.1%
Green Mountain Power	VT	Green Mountain Power	No	NE-ISO	5,954	2,021	Owner	Historical	Appointed	8.57%	Not Reported	83.2%
Gulf Power	FL	NextEra Energy	No	PJM	7,558	1,682	No	Forecast	Appointed	10 25% (Settled)	9 38%	87.7%

UTILITY OPERATING AND FINANCIAL STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Holding Company Included in Dr. Morin's Proxy Group	RTO/ISO	Size of Service Territory (sq miles)	Transmission Pole Miles	Nuclear Plant Ownership and Operation	Test Year Period	Commissioner Selection Process	Most Recent Electric ROE Approved by the PUC	Operating Utility Actual 2021 Year-End Return on Equity	Residential Customers Served Year-End 2021
Idaho Power	ID, OR	IDACORP	Yes	None	28,533	4,780	No	ID: Historical OR: Forecast	ID: Appointed OR: Appointed	ID: 9.50% (Settled) OR: 9.90% (Settled)	10.08%	D: 84.2% OR: 70.1%
Indiana Michigan Power	N, MI	American Electric Power (AEP)	Yes	PJM	4,569	3,586	Owner and Operator	N: Historical with Known and Measurable Changes MI: Forecast	IN: Appointed MI: Appointed	IN: 9.70% (Settled) MI: 9.86% (Settled)	10.11%	N: 87.5% MI: 85 3%
Interstate Power & Light	IA	Alliant Energy Corp.	Yes	MISO	9,366	None	No	Historical with Known and Measurable Changes	Appointed	10.02% (Settled)	9 29%	82.5%
Kentucky Power	KY	American Electric Power (AEP)	Yes	PJM	3,785	1,324	No	Historical	Appointed	9.30%	5 91%	80.9%
Kentucky Utilities	KY, VA	PPL	No	None	4,741	4,056	No	KY: Historical VA: Historical	KY: Appointed VA: Elected (by Legislature)	KY: 9.43% (Settled) VA: 9.40% (Settled)	7.68%	KY: 82.2% VA: 83.0%
Kingsport Power	TN	American Electric Power (AEP)	Yes	PJM	54	72	No	Forecast	Appointed	9.85% (Settled)	Not Reported	87.1%
Liberty Utilities Central (Empire District Electric)	AR, KS, MO, OK	Algonquin	No	SPP	1,834	1,414	No	AR: Historical with Known and Measurable Changes KS: Historical MO: Historical OK: Historical	AR: Appointed KS: Appointed MO: Appointed OK: Elected	AR: Not calculated in settlement KS: Not calculated in settlement MO: 9 25% (Settled) OK: 9.50% (Settled)	Not Reported	AR: 84 3% KS: 84.6% MO: 84.5% OK: 79 9%
Lockhart Power	SC	Pacolet Milliken	No	None	191	92	No	Historical	Elected (by Legislature)	12.00%	Not Reported	78.7%
Louisville Gas & Electric	KY	PPL	No	None	737	918	No	Historical	Appointed	9.43%	8 26%	87.8%
Madison Gas & Electric	WI	MGE Energy, Inc.	Yes	MISO	250	None	No	Forecast	Appointed	9.80%	10.22%	86.2%
MidAmerican Energy	IA, IL, SD	Berkshire Hathaway Energy	No	MISO	9,842	4,296	Owner	L: Historical or Forecast IA: Historical with Known and Measurable Changes SD: Historical	L: Appointed IA: Appointed SD: Elected	IA: 10.00% (Settled) IL: 9 56% SD: Not disclosed in settlement	10.50%	IA: 85.73% IL: 86.5% SD: 80.4%
Minnesota Power	MN	Allete	No	MISO	2,398	3,087	No	Forecast	Appointed	Not calculated in Settlement	Not Reported	83.6%
Mississippi Power	MS	Southern	Yes	None	1,140	2,214	No	Forecast	Elected	Not disclosed in settlement	8.81%	81.9%
Monongahela Power	WV	FirstEnergy	Yes	PJM	15,585	2,015	No	Historical	Appointed	9.47%	11.55%	84.6%

UTILITY OPERATING AND FINANCIAL STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Holding Company Included in Dr. Morin's Proxy Group	RTO/ISO	Size of Service Territory (sq miles)	Transmission Pole Miles	Nuclear Plant Ownership and Operation	Test Year Period	Commissioner Selection Process	Most Recent Electric ROE Approved by the PUC	Operating Utility Actual 2021 Year-End Return on Equity	Residential Customers Served Year-End 2021
Montana-Dakota Utilities	MT, ND, SD, WY	MDU Resources	No	SPP	20,388	3,430	No	MT: Historical ND: Historical or Forecast SD: Historical WY: Historical	MT: Elected ND: Elected SD: Elected WY: Appointed	MT: Not disclosed in settlement ND: 9.65% (Settled) SD: Not disclosed in settlement WY: 9.45% (Settled)	Not Reported	MT: 77 3% ND: 84 5% SD: 75.6% WY: 84.2%
Nevada Power (NV Energy)	NV	Berkshire Hathaway Energy	No	None	4,571	1,908	No	Historical	Appointed	9.40%	10.15%	88.5%
Northern Indiana Public Service	IN	NiSource	No	MISO	2,734	1,229	No	Historical	Appointed	9.75%	Not Reported	87.4%
Northern States Power--MN	MN, ND, SD	Xcel Energy	Yes	MISO	8,861	5,856	Owner and Operator	MN: Forecast ND: Historical or Forecast SD: Historical	MN: Appointed ND: Elected SD: Elected	MN: 9 20% (Settled) ND: 9.50% (Settled) SD: Not disclosed in settlement	9 95%	MN: 89 2% ND: 86.0% SD: 87.0%
Northern States Power--WI	MI, WI	Xcel Energy	Yes	MISO	9,176	2,687	No	MI: Forecast WI: Forecast	MI: Appointed WI: Appointed	MI: 9.70% (Settled) WI: 10.00% (Settled)	9 95%	MI: 85.0% WI: 84.0%
NorthWestern Energy Montana	MT, WY	NorthWestern Corp.	Yes	None	32,775 (MT and SD)	8,127 Northwestern	No	MT: Historical WY: Historical	MT: Elected WY: Appointed	MT: 9.65% (Settled) WY: Not regulated	Not Reported	MT: 80 5% WY: 35.9%
NorthWestern Energy South Dakota	SD	NorthWestern Corp.	Yes	SPP	32,775 (MT and SD)	8,127 Northwestern	No	Historical	Elected	Not disclosed in settlement	Not Reported	79.4%
Northwestern Wisconsin Electric	MN, WI	Northwestern Wisconsin Power	No	MISO	932	151	No	MN: Forecast WY: Forecast	MN: Appointed WI: Appointed	MN: Not Calculated WI: 11.00%	Not Reported	MN: 75.0% WI: 87.0%
Oklahoma Gas & Electric	AR, OK	OGE Energy	Yes	SPP	27,848	5,928	No	AR: Historical with Known and Measurable Changes OK: Historical	AR: Appointed OK: Elected	AR: Not calculated in Settlement OK: 9.50% (Settled)	8 39%	AR: 83 2% OK: 85 3%
Otter Tail Power	MN, ND, SD	Otter Tail Corp.	Yes	MISO	9,014	6,187	No	MN: Forecast ND: Historical or Forecast SD: Historical	MN: Appointed ND: Elected SD: Elected	MN: 9.48% ND: 9.77% (Settled) SD: 8.75%	Not Reported	MN: 79 2% ND: 77.0% SD: 75.7%
Pacific Gas & Electric	CA	PG&E	No	CAISO	67,283	36,672	Owner and Operator	Forecast	Appointed	10 25%	0.49%	86.3%
PacifiCorp	CA, D, OR, UT, WA, WY	Berkshire Hathaway Energy	No	None	139,766	18,020	No	CA: Forecast ID: Historical OR: Forecast UT: Forecast WA: Historical WY: Historical	CA: Appointed ID: Appointed OR: Appointed UT: Appointed WA: Appointed WY: Appointed	CA:10.00% ID: Not calculated in settlement OR: 9 50% UT: 9.65% WA: 9 50% (Settled) WY: 9.50%	0 90%	CA: 79 3% D: 81.8% OR: 86.8% UT: 89.4% WA: 83.4% WY: 81.6%
Portland General Electric	OR	Portland General	Yes	None	4,106	1,570	No	Forecast	Appointed	9.50% (Settled)	9.15% (ROACE)	87.8%

UTILITY OPERATING AND FINANCIAL STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Holding Company Included in Dr. Morin's Proxy Group	RTO/ISO	Size of Service Territory (sq miles)	Transmission Pole Miles	Nuclear Plant Ownership and Operation	Test Year Period	Commissioner Selection Process	Most Recent Electric ROE Approved by the PUC	Operating Utility Actual 2021 Year-End Return on Equity	Residential Customers Served Year-End 2021
Public Service Company of New Mexico	NM	PNM Resources	No	None	3,292	3,424	Owner	Historical with Known and Measurable Changes	Elected	9.58% (Settled)	8 32%	89.0%
Public Service Company of Oklahoma	OK	American Electric Power (AEP)	Yes	SPP	4,604	2,670	No	Historical	Elected	9.40% (Settled)	7 35%	85.8%
Public Service Company of Colorado	CO	Xcel Energy	Yes	None	15,629	4,864	No	Historical or Forecasted	Appointed	9.30%	8 23%	85.6%
Puget Sound Energy	WA	Puget Energy	No	None	9,289	2,613	No	Historical	Appointed	9.40%	7.75% (ROACE)	88.0%
San Diego Gas & Electric	CA	Sempra	Yes	CAISO	4,087	25,125	No	Forecast	Appointed	10 20%	10.25%	94.4%
Sierra Pacific Power (NV Energy)	NV	Berkshire Hathaway Energy	No	None	40,973	2,517	No	Historical with Known and Measurable Changes	Appointed	9.70% (Settled)	8.42%	86.6%
Southern California Edison	CA	Edison Intl.	Yes	CAISO	51,407	12,153	Owner	Forecast	Appointed	10 30%	13.65%	87.0%
Southern Indiana Gas & Electric Co.	IN	CenterPoint	Yes	MISO	1,479	1,032	No	Historical with Known and Measurable Changes	Appointed	10.40%	9.45% (ROACE)	87.2%
Southwestern Electric Power	AR, LA, TX	American Electric Power (AEP)	Yes	SPP	10,041	4,106	No	AR: Historical with Known and Measurable Changes LA: Historical TX: Historical	AR: Appointed LA: Elected TX: Appointed	AR: 9.50% LA: 10.00% (Settled) TX - 9.25%	8 59%	AR: 84 5% LA: 88.4% TX: 81.4%
Southwestern Public Service	NM, TX	Xcel Energy	Yes	SPP	17,048	7,969	No	NM: Historical with Known and Measurable Changes TX: Historical	NM: Elected TX: Appointed	NM: 9 35% (Settled) TX: 9.45% (Settled)	9.22%	NM: 78.7% TX: 78.9%
Tampa Electric	FL	Emera	No	None	1,719	1,345	No	Forecast	Appointed	9.95% (Settled)	9 90%	88.9%
Tucson Electric Power	AZ	Fortis	No	None	1,002	2,231	No	Historical	Elected	9.15%	8 26%	90.5%
UNS Electric	AZ	Fortis	No	None	8,069	343	No	Historical	Elected	9.50%	Not Reported	88.3%
Upper Peninsula Power	MI	None	No	MISO	6,326	None	No	Forecast	Appointed	9.90% (Settled)	Not Reported	88.4%
Wheeling Power	WV	American Electric Power (AEP)	Yes	PJM	421	200	No	Historical	Appointed	9.75% (Settled)	Not Reported	83.6%
Wisconsin Electric Power	MI, WI	WEC Energy Group	Yes	MISO	6,089	None	No	MI: Forecast WI: Forecast	MI: Appointed WI: Appointed	MI: 10.10% WI: 10.00% (Settled)	10.06%	89.6%

UTILITY OPERATING AND FINANCIAL STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Holding Company Included in Dr. Morin's Proxy Group	RTO/ISO	Size of Service Territory (sq miles)	Transmission Pole Miles	Nuclear Plant Ownership and Operation	Test Year Period	Commissioner Selection Process	Most Recent Electric ROE Approved by the PUC	Operating Utility Actual 2021 Year-End Return on Equity	Residential Customers Served Year-End 2021
Wisconsin Power & Light	WI	Alliant Energy Corp.	Yes	MISO	9,790	None	No	Forecast	Appointed	10.00% (Settled)	10.11%	87.1%
Wisconsin Public Service	MI, WI	WEC Energy Group	Yes	MISO	11,005	None	No	MI: Forecast WI: Forecast	MI: Appointed WI: Appointed	MI: 10.20 (Settled) WI: 10.00% (Settled)	10.85%	87.9%

UTILITY CLEAN ENERGY AND RELATED STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Utility Clean/Renewable Electric Energy Commitment/Goal	Holding Company Clean/Renewable Electric Energy Commitment/Goal	State Clean/Renewable Energy Standard/Goal	Energy/Resource Mix	Fossil Capacity Planned for Retirement	Securitization Enabled	Net Energy Metering or RCP Policy	Installed Community Solar Capacity end of 2021
(A)	*(B)*	*(C)*	*(N)*	*(O)*	*(P)*	*(Q)*	*(R)*	*(S)*	*(T)*	*(U)*
AES Indiana (Indianapolis Power & Light)	IN	AES	Exit coal: 81% by 2025	Exit coal: 90% by 2025 Reduce CO2 Emissions: 70% by 2030 Clean: 100% by 2040	Clean Goal: 10% by 2025	2019 Resource Mix: Coal: 43% Natural Gas/Oil: 46% Renewable: 11%	422 MW in 2023	Yes	Yes	None
Alabama Power	AL	Southern	Exit Coal by 2028 Clean: 100% by 2050	Clean: 100% by 2050	None	2021 Resource Mix: Coal: 46% Nuclear: 24% Natural Gas: 19% Hydro: 8%	1,267 MW by 2028	No	No	None
Ameren Missouri (Union Electric)	MO	Ameren	Clean: 100% by 2045	Clean: 100% by 2050	Renewable: 15% by 2021	2022 Resource Mix: Coal: 50% Nuclear: 12% Natural Gas: 30% Hydro: 4% Renewable: 4%	974 MW in 2028 1,244 MW in 2029	Yes	Yes	1 9 MW-AC
Appalachian Power	VA, WV	American Electric Power (AEP)	See Holding Company	Renewable: 50% by 2030 Clean: 80% by 2030 Clean: 100% by 2050	VA: Renewable: 100% by 2050 (specific to Appalachian Power) WV: None	2022 AEP Corp Resource Mix: Coal: 41% Nuclear: 7% Natural Gas: 27% Renewables/EE/Hydro: 23%	None reported	VA: No WV: Yes	VA: Yes WV: Yes	None
Arizona Public Service	AZ	Pinnacle West	Renewable: 45% by 2030 Exit Coal by 2031 Clean: 65% by 2030 Clean: 100% by 2050	Clean: 100% by 2050	Renewable: 15% by 2025	2021 Energy Mix: Coal: 16% Nuclear: 25% Natural Gas: 29% Renewable/DSM: 25%	403 MW in 2025 970 MW in 2031	No	Yes	None
Avista Utilities	ID, WA	Avista Corp.	Clean: 62.5% by 2025	Carbon neutral: 100% by 2027 Clean: 100% by 2045	ID: None WA: Clean: 100% by 2045	2021 Energy Mix: Coal: 13% Natural Gas: 40% Hydro: 34% Renewables/Unspecified: 12%	45 MW in 2035	D: Yes WA: Yes	Yes	423 kW-AC
Black Hills Power	MT, SD, WY	Black Hills Corp.	Reduce Emissions: 80% by 2030	Reduce Emissions: 80% by 2040	MT: Renewable: 15% by 2015 SD: Renewable Goal: 10% by 2015 WY: None	2021 Corporate Resource Mix: Coal: 26% Natural Gas: 51% Wind: 20%	66 MW in 2039	MT: Yes SD: No WY: No	Yes	None
Black Hills Colorado Electric Utility	CO	Black Hills Corp.	Reduce Emissions: 80% by 2030	Reduce Emissions: 80% by 2040	Renewable: 30% by 2020 Clean Goal: 100% by 2050	2021 Corporate Resource Mix: Coal: 26% Natural Gas: 51% Wind: 20%	None reported	Yes	Yes	3 5 MW-AC
Cheyenne Light Fuel & Power	WY	Black Hills Corp.	See Holding Company	Reduce Emissions: 80% by 2040	WY: None	2021 Corporate Resource Mix: Coal: 26% Natural Gas: 51% Wind: 20%	None reported	No	Yes (DBA Black Hills)	None

UTILITY CLEAN ENERGY AND RELATED STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Utility Clean/Renewable Electric Energy Commitment/Goal	Holding Company Clean/Renewable Electric Energy Commitment/Goal	State Clean/Renewable Energy Standard/Goal	Energy/Resource Mix	Fossil Capacity Planned for Retirement	Securitization Enabled	Net Energy Metering or RCP Policy	Installed Community Solar Capacity end of 2021
CLECO Power	LA	Cleco Corp.	See Holding Compasny	Reduce GHG Emissions: 60% by 2030 Clean: 100% by 2050	LA: None	2022 Generating Assets: Coal/Petrol Coke: 26% Natural Gas: 72% Waste Heat: 2%	None reported	Yes	Yes	None
Consolidated Water Power	WI	Verso Minnesota Wisconsin	None	None	Renewable: 10% by 2015 Clean Goal: 100% by 2050	Owned Generation: Hydro: 100%	None reported	Yes	Yes	None
Consumers Energy	MI	CMS Energy	See Holding Company	Exit coal by 2025 Reduce CO2 Emissions: 90% by 2025 Renewable: 60% by 2040 Net Zero Carbon: 100% by 2040	Renewable: 15% by 2021	2021 Resource Mix: Coal: 35% Natural Gas: 44% Hydro: 19% Renewables: 2%	486 MW in 2023 1,333 MW in 2025	Yes	Yes	4.0 MW-AC
Dahlberg Light & Power	WI	Dahlberg	None	None	Renewable: 10% by 2015 Clean Goal: 100% by 2050	Owned Generation: Oil/Diesel: 100%	None reported	Yes	Yes	None
Dominion Energy Virginia (Virginia Electric Power)	NC, VA	Dominion Energy	See Holding Company	Clean: 100% by 2050	NC:Carbon Neutral Goal: 100% by 2050 VA: Renewable: 100% by 2045 (specific to Dominion)	2021 Dominion Generating Units: Coal: 19% Nuclear: 18% Natural Gas/Oil: 51% Renewables/Hydro: 12%	1,796 MW in 2023	NC: Yes VA: No	Yes	None
Dominion Energy South Carolina	SC	Dominion Energy	See Holding Company	Clean: 100% by 2050	Renewable Goal: 2% by 2021	2021 Dominion Generating Units: Coal: 19% Nuclear: 18% Natural Gas/Oil: 51% Renewables/Hydro: 12%	60 MW in 2023 26 MW in 2024	Yes	Yes	None
DTE Electric	MI	DTE Energy Co.	See Holding Company	Net-Zero Carbon/GHG: 100% by 2050	Renewable: 15% by 2021	2021 Fuel Mix: Coal: 58% Nuclear: 23% Natural Gas: 9% Renewable/Hydro: 10%	1,560 MW in 2022 1,034 MW in 2028	Yes	Yes	None
Duke Energy Carolinas	NC, SC	Duke Energy	See Holding Company	Exit coal by 2035 Clean: 100% by 2050	NC: Carbon Neutral Goal: 100% by 2021 SC: Renewable Goal: 2% by 2021	2021 Resource Mix: Coal: 28% Nuclear: 32% Natural Gas: 26% Hydro: 4% Renewable/Storage: 10%	421 MW in 2023	NC: Yes SC: Yes	Yes	2.0 MW-AC
Duke Energy Florida	FL	Duke Energy	See Holding Company	Exit coal by 2035 Clean: 100% by 2050	None	2021 Resource Mix: Coal: 24% Nuclear: 26% Natural Gas/Oil: 47% Hydro: 2% Renewable/Storage: 1%	1,410 MW in 2034	Yes	Yes	None

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Utility Name	State (Electric Service)	Holding Company	Utility Clean/Renewable Electric Energy Commitment/Goal	Holding Company Clean/Renewable Electric Energy Commitment/Goal	State Clean/Renewable Energy Standard/Goal	Energy/Resource Mix	Fossil Capacity Planned for Retirement	Securitization Enabled	Net Energy Metering or RCP Policy	Installed Community Solar Capacity end of 2021
Duke Energy Indiana	IN	Duke Energy	See Holding Company	Exit coal by 2035 Clean: 100% by 2050	Clean Goal: 10% by 2025	2021 Resource Mix: Coal/Coal Gas: 73% Natural Gas/Oil: 25% Hydro: 1% Renewable/Storage: 1%	310 MW in 2025 995 MW in 2027 1,252 MW in 2029 1,855 MW in 2035	Yes	Yes	None
Duke Energy Kentucky	KY	Duke Energy	See Holding Company	Exit coal by 2035 Clean: 100% by 2050	None	2021 Resource Mix: Coal: 57% Natural Gas: 42% Renewable: 1%	600 MW in 2035	Yes	Yes	None
Duke Energy Progress	NC, SC	Duke Energy	See Holding Company	Exit coal by 2035 Clean: 100% by 2050	NC: Carbon Neutral Goal: 100% by 2021 SC: Renewable Goal: 2% by 2021	2021 Resource Mix: Coal: 12% Natural Gas/Oil: 83% Renewable/Storage: 5%	1,392 MW in 2027-33 704 MW in 2028-35	NC: Yes SC: Yes	Yes - OH	610 kW-AC
El Paso Electric	NM, TX	El Paso Electric	See Holding Company	Clean: 80% by 2035 Clean: 100% by 2045	NM: Renewable: 80% by 2040 Clean Goal: 100% by 2045 TX: Renewable: 5880 MW by 2015; Goal: 10,000 MW by 2025	2021 Owned Resources: Nuclear: 30% Natural Gas: 70% Renewables: <1%	46 MW in 2023 197 MW in 2024 322 MW in 2026 63 MW in 2030	NM: Yes TX: Yes	Yes	3.0 MW-AC
Entergy Arkansas	AR, TN	Entergy Corp.	See Holding Company	Clean: 100% by 2050	AR: None	2021 Resource Mix: Coal: 16% Nuclear: 36% Natural Gas: 41% Hydro: 1% Renewables: 6%	522 MW in 2025	AR: Yes	Yes	181 kW-AC
Entergy Louisiana	LA	Entergy Corp.	Reduce CO2 Emissions: 50% by 2030	Clean: 100% by 2050	None	2021 Resource Mix: Coal: 1% Nuclear: 19% Natural Gas: 77% Hydro: 2% Renewables: 1%	47 MW in 2022 422 MW in 2024 412 MW in 2026 513 MW in 2029 738 MW in 2031 742 MW in 2033	Yes	Yes	None
Entergy Mississippi	MS	Entergy Corp.	See Holding Company	Clean: 100% by 2050	None	2021 Owned Resources: Coal: 3% Natural Gas: 97% Renewables: <1%	494 MW in 2023 706 MW in 2035	Yes	Yes	None
Entergy New Orleans	LA	Entergy Corp.	See Holding Company	Clean: 100% by 2050	None	2021 Owned Resources: Natural Gas: 97% Renewables: 3%	None reported	Yes	Yes	None
Entergy Texas	TX	Entergy Corp.	See Holding Company	Clean: 100% by 2050	Renewable: 5880 MW by 2015; Goal: 10,000 MW by 2025	2021 Owned Resources: Coal: 2% Natural Gas: 98%	212 MW in 2023 863 MW in 2026 500 MW in 2034	Yes	Yes	None
Evergy Kansas Central	KS	Evergy Inc.	See Holding Company	Reduce CO2 Emissions: 100% by 2045	Renewable Goal: 20% by 2020	2022 Evergy Owned Resources: Coal: 38% Nuclear: 7% Natural Gas: 26% Renewables: 29%	None reported	Yes	Yes	None

UTILITY CLEAN ENERGY AND RELATED STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Utility Clean/Renewable Electric Energy Commitment/Goal	Holding Company Clean/Renewable Electric Energy Commitment/Goal	State Clean/Renewable Energy Standard/Goal	Energy/Resource Mix	Fossil Capacity Planned for Retirement	Securitization Enabled	Net Energy Metering or RCP Policy	Installed Community Solar Capacity end of 2021
Evergy Kansas South	KS	Evergy Inc.	See Holding Company	Reduce CO2 Emissions: 100% by 2045	Renewable Goal: 20% by 2020	2022 Evergy Owned Resources: Coal: 38% Nuclear: 7% Natural Gas: 26% Renewables: 29%	None reported	Yes	Yes	None
Evergy Metro	KS, MO	Evergy Inc.	See Holding Company	Reduce CO2 Emissions: 100% by 2045	KS: Renewable Goal: 20% by 2020 MO: Renewable: 15% by 2021	2022 Evergy Owned Resources: Coal: 38% Nuclear: 7% Natural Gas: 26% Renewables: 29%	None reported	KS: Yes MO: Yes	Yes	None
Evergy Missouri West	MO	Evergy Inc.	See Holding Company	Reduce CO2 Emissions: 100% by 2045	Renewable: 15% by 2021	2022 Evergy Owned Resources: Coal: 38% Nuclear: 7% Natural Gas: 26% Renewables: 29%	97 MW in 2024	Yes	Yes	None
Florida Power & Light	FL	NextEra Energy	See Holding Company	Clean: 100% by 2045	None	2022 FPL Owned Resources: Coal: 3% Nuclear: 12% Natural Gas/Oil: 73% Renewables/Storage: 12%	None reported	Yes	Yes	1,409 MW-AC
Georgia Power	GA	Southern	Exit coal: 70% by 2028 Clean: 100% by 2050	Reduce GHG Emissions: 50% by 2025 Clean: 100% by 2050	None	2020 Energy Mix: Coal: 13% Nuclear: 24% Natural Gas/Oil: 50% Hydro: 5% Renewable: 8%	3,536 MW by 2028	No	Yes	8.0 MW-AC
Green Mountain Power	VT	Green Mountain Power	See Holding Company	Reduce CO2 Emissions: 100% by 2025 Renewable:100% by 2030	Renewable: 75% by 2032	2021 Energy Mix: Nuclear: 21% Hydro: 75% Renewables: 4%	None reported	No	Yes	3 2 MW-AC
Gulf Power (Florlisa Power & Light)	FL	NextEra Energy	See Holding Company	Clean: 100% by 2045	None	2022 FPL Owned Resources: Coal: 3% Nuclear: 12% Natural Gas/Oil: 73% Renewables/Storage: 12%	12 MW in 2026 251 MW in 2027	Yes	Yes	None
Idaho Power	D, OR	DACORP	See Holding Company	Clean: 100% by 2045	ID: None OR: Emissions Reduction Target: 100% by 2040	2021 Energy Mix: Coal: 17% Natural Gas: 15% Hydro: 33% Renewables 18% Purchases: 17%	706 MW in 2037	ID: Yes OR: Yes	Yes	None
Indiana Michigan Power	N, MI	American Electric Power (AEP)	See Holding Company	Renewable: 50% by 2030 Clean: 80% by 2030 Clean: 100% by 2050	IN:Clean Goal: 10% by 2025 MI: Renewable: 15% by 2021	2021 Energy Mix: Coal: 48% Nuclear: 42% Renewables: 10%	261 MW in 2025 1,300 MW in 2028	IN: Yes MI: Yes	N: Yes MI: Yes	None

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Utility Name	State (Electric Service)	Holding Company	Utility Clean/Renewable Electric Energy Commitment/Goal	Holding Company Clean/Renewable Electric Energy Commitment/Goal	State Clean/Renewable Energy Standard/Goal	Energy/Resource Mix	Fossil Capacity Planned for Retirement	Securitization Enabled	Net Energy Metering or RCP Policy	Installed Community Solar Capacity end of 2021
Interstate Power & Light	IA	Alliant Energy	See Holding Company	Reduce CO2 Emissions: 50%l by 2030 Exit coal: 100% by 2040 Clean: 100% by 2050	105 MW (no deadline)	2021 Resource Mix: Coal: 29% Natural Gas: 25% Renewable: 39% Purchases: 7%	241 MW in 2022 35 MW in 2026	No	Yes	None
Kentucky Power	KY	American Electric Power (AEP)	See Holding Company	Renewable: 50% by 2030 Clean: 80% by 2030 Clean: 100% by 2050	None	2022 AEP Corp Resource Mix: Coal: 41% Nuclear: 7% Natural Gas: 27% Renewables/EE/Hydro: 23%	None reported	Yes	Yes	None
Kentucky Utilities	KY, VA	PPL	See Holding Company	Reduce CO2 Emissions: 70% by 2035 Reduce CO2 Emissions: 80% by 2040 Reduce CO2 Emissions: 100% by 2050	KY: None VA: Renewable: 100% by 2045	2022 Owned Resources: Coal: 78% Natural Gas: 21% Hydro: 1%	None reported	KY: Yes VA: No	Yes	2.0 MW-AC
Kingsport Power	TN	American Electric Power (AEP)	See Holding Company	Renewable: 50% by 2030 Clean: 80% by 2030 Clean: 100% by 2050	None	2022 AEP Corp Resource Mix: Coal: 41% Nuclear: 7% Natural Gas: 27% Renewables/EE/Hydro: 23%	None reported	No	Yes	None
Liberty Utilities (Empire District Electric)	AR, KS, MO, OK	Algonquin	See Holding Company	Clean: 100% by 2050	AR: None KS: Renewable Goal: 20% by 2020 MO: Renewable: 15% by 2021 OK: Renewable Goal: 15% by 2021	2020 Owned Resources: Natural Gas/Oil: 49% Hydro: 4% Renewable: 47%	178 MW in 2026	AR: Yes KS: Yes MO: Yes OK: Yes	Yes	None
Lockhart Power	SC	Pacolet Milliken	Renewable: 100% (no time frame)	None	Renewable Goal: 2% by 2021	2020 Owned Resources: Diesel: 27% Hydro: 70% Renewable: 3%	None reported	Yes	Yes	None
Louisville Gas & Electric	KY	PPL	See Holding Company	Clean: 100% by 2050 Reduce CO2 Emissions: 70% by 2035 Reduce CO2 Emissions: 80% by 2040	None	2022 Owned Resources: Coal: 60% Natural Gas: 36% Hydro: 4%	None reported	Yes	Yes	None
Madison Gas & Electric	WI	MGE Energy	See Holding Company	Reduce CO2 Emissions: 80% by 2030 Clean: 100% by 2050	Renewable: 10% by 2015 Clean Goal: 100% by 2050	2022 Resource Mix: Coal: 35% Natural Gas: 33% Renewable: 32%	110 MW in 2023 109 MW in 2024	Yes	Yes	5 5 MW-AC
MidAmerican Energy	IL, IA, SD	Berkshire Hathaway Energy	See Holding Company	Net-Zero GHG Emissions by 2050	L: Renewable: 25% by 2026 IA: Renewable: 105 MW (no deadline) SD: Renewable Goal: 10% by 2015	2022 Resource Mix: Coal: 23% Nuclear: 4% Natural Gas: 11% Renewable: 62%	None reported	IL: Yes IA: No SD: No	Yes	None
Minnesota Power	MN	Allete	Reduce CO2 Emissions: 100% by 2050	Exit coal: 100% by 2035 Reduce CO2 Emissions: 80% by 2035 Reduce CO2 Emissions: 100% by 2050	Renewable: 26.5% by 2025	2021 Energy Mix: Coal: 28% Natural Gas: 1% Renewable: 13% Purchases: 58%	355 MW in 2030	Yes	Yes	1.1 MW-AC

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Utility Name	State (Electric Service)	Holding Company	Utility Clean/Renewable Electric Energy Commitment/Goal	Holding Company Clean/Renewable Electric Energy Commitment/Goal	State Clean/Renewable Energy Standard/Goal	Energy/Resource Mix	Fossil Capacity Planned for Retirement	Securitization Enabled	Net Energy Metering or RCP Policy	Installed Community Solar Capacity end of 2021
Mississippi Power	MS	Southern	See Holding Company	Clean: 100% by 2050 Reduce GHG Emissions: 50% by 2025	None	2022 Resource Mix: Coal: 14% Natural Gas: 86%	236 MW in 2023 502 MW in 2027	Yes	Yes	None
Monongahela Power	WV	FirstEnergy	See Holding Company	Carbon Neutral: 100% by 2050	None	2022 Resource Mix: Coal: 100%	None reported	Yes	Yes - WV	None
Montana-Dakota Utilities	MT, ND, SD, WY	MDU Resources	See Holding Company	Reduce GHG Emissions: 45% by 2030	MT: Renewable: 15% by 2015 ND: Renewable Goal: 10% by 2015 SD: Renewable Goal: 10% by 2015 WY: None	2022 Resource Mix: Coal: 37% Natural Gas: 31% Renewable: 32%	None reported	MT: Yes ND: No SD: No WY: No	MT: Yes SC: No	None
Nevada Power (NV Energy)	NV	Berkshire Hathaway Energy	See Holding Company	Net-Zero GHG Emissions by 2050	Renewable: 50% by 2030 Clean Goal: 100% by 2050	2022 Owned Resources: Natural Gas: 99% Renewable: 1%	None reported	No	Yes	None
Northern Indiana Public Service	IN	NiSource	Exit coal by 2028	Reduce GHG Emissions: 50% by 2025 Reduce GHG Emissions: 90% by 2030	Clean Goal: 10% by 2025	2021 Resource Mix: Coal: 67% Natural Gas: 20% Renewable: 13%	722 MW in 2023 456 MW in 2028	Yes	Yes	None
Northern States Power--MN	MN, ND, SD	Xcel Energy	See Holding Company	Reduce CO2 Emissions: 85% by 2030 Reduce CO2 Emissions: 100% by 2050	MN: Renewable: 26 5% by 2025 ND: Renewable Goal: 10% by 2015 SD: Renewable Goal: 10% by 2015	2021 Enerrgy Mix (Total NSP): CoaL: 18% Nuclear: 27% Natural Gas: 22% Renewable: 34%	957 MW in 2023 1,094 MW in 2025 286 MW in 2026 282 MW in 2031 876 MW in 2034 212 MW in 2058	MN: Yes ND: No SD: No	Yes	841 MW-AC
Northern States Power--WI	MI, WI	Xcel Energy	See Holding Company	Reduce CO2 Emissions: 85% by 2030 Reduce CO2 Emissions: 100% by 2050	MI: Renewable: 15% by 2021	2021 Enerrgy Mix (Total NSP): CoaL: 18% Nuclear: 27% Natural Gas: 22% Renewable: 34%	None reported	MI: Yes WI: Yes	Yes	2 MW-AC
NorthWestern Energy Montana	MT, WY	NorthWestern Corp.	See Holding Company	Clean: 100% by 2050	MT: Renewable: 15% by 2015 WY: None	2021 Energy Mix: Coal: 23% Natural Gas: 18% Hydro: 35% Renewable: 24%	None reported	MT: Yes WY: No	Yes	None
NorthWestern Energy South Dakota	SD	NorthWestern Corp.	See Holding Company	Clean: 100% by 2050	SD: Renewable Goal: 10% by 2015	2021 Energy Mix: Coal: 52% Natural Gas: 4% Renewable: 44%	None reported	No	Yes	None
Northwestern Wisconsin Electric	MN, WI	Northwestern Wisconsin Power	See Holding Company	Clean: 100% by 2050	MN: Renewable: 26 5% by 2025 WI: Renewable: 10% by 2015 Clean: 100% by 2050	Owned Generation: Diesel: 100%	None reported	MN: Yes WY: No	Yes	None
Oklahoma Gas & Electric	AR, OK	OGE Energy	Reduce CO2 Emissions: 50% by 2030	Reduce Emissions: 40% by 2030 Exit Fossil Fuel: 95% by 2050	AR: None OK: Renewable Goal: 15% by 2015	2021 Resource Mix: Coal: 40% Natural Gas: 48% Renewable: 12%	168 MW in 2023	AR: Yes OK: Yes	Yes	10 MW-AC

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Otter Tail Power	MN, ND, SD	Otter Tail Corp.	Reduce CO2 Emissions: 50% by 2025 Reduce CO2 Emissions: 97% by 2050	Reduce CO2 Emissions: 50% by 2025	MN: Renewable: 26 5% by 2025 ND: Renewable Goal: 10% by 2015 SD: Renewable Goal: 10% by 2015	2021 Owned Resources: Coal: 38% Natural Gas/Oil: 33% Hydro: 2% Renewables: 27%	None reported	MN: Yes ND: No SD: No	Yes	None
Pacific Gas & Electric	CA	PG&E	See Holding Company	Renewable: 60% by 2030	Renewable: 60% by 2030 Clean: 100% by 2045	2021 Energy Mix: Nuclear: 29% Natural Gas: 18% Hydro: 50% Renewable: 2%	None reported	Yes	Yes	15.3 MW-AC
PacifiCorp	CA, D, OR, UT, WA, WY	Berkshire Hathaway Energy	Reduce GHG Emissions: 74% by 2030	Net-Zero GHG Emissions: 100% by 2050	CA: Renewable: 60% by 2030 Clean: 100% by 2045 ID: None OR: Emissions Reduction Goal: 100% by 2040 UT: Renewable Goal: 20% by 2025 WA: Renewable: 15% by 2020 Clean: 100% by 2045 WY: None	2021 Owned/Contracted Mix: Coal: 33% Natural Gas: 19% Hydro: 9% Renewable: 39%	357 MW in 2025 745 MW in 2027 46 MW in 2028 247 MW in 2029 354 MW in 2032 909 MW in 2036 1,412 MW in 2037 265 MW in 2039 477 MW in 2043	CA: Yes D: Yes OR: Yes UT: No WA: Yes WY: No	Yes	617 MW-AC
Portland General Electric	OR	Portland General	See Holding Company	Reduce GHG Emissions: 80% by 2030 Reduce GHG Emissions: 100% by 2050	Emissions Reduction Goal: 100% by 2040	2019 Resource Mix: Coal: 8% Natural Gas/Oil: 50% Hydro: 13% Renewable: 29%	None reported	Yes	Yes	34.3 MW-AC
Public Service Company of New Mexico	NM	PNM Resources	See Holding Company	Clean: 100% by 2040	Renewable: 80% by 2040 Clean Goal: 100% by 2050	2022 Owned/Contracted Mix: Coal: 27% Nuclear: 14% Natural Gas: 36% Renewable: 23%	847 MW in 2022	Yes	Yes	None
Public Service Company of Oklahoma	OK	American Electric Power (AEP)	See Holding Company	Renewable: 50% by 2030 Clean: 80% by 2030 Clean: 100% by 2050	Renewable Goal: 15% by 2015	2022 Energy Mix: Coal: 11% Natural Gas: 19% Renewable: 24% Purchases: 46%	164 MW in 2023	Yes	Yes	None
Public Service Company of Colorado	CO	Xcel Energy	See Holding Company	Reduce CO2 Emissions: 85% by 2030 Reduce CO2 Emissions: 100% by 2050	Renewable: 30% by 2020 Clean Goal: 100% by 2050	2021 Energy Mix: Coal: 32% Natural Gas: 29% Renewable: 39%	325 MW in 2022 216 MW in 2025 172 MW in 2026 572 MW in 2027 98 MW in 2028	Yes	Yes	22.7 MW-AC
Puget Sound Energy	WA	Puget Energy	See Holding Company	Net-Zero Emissions: 100% by 2030 Reduce CO2 Emissions: 100% by 2045	Renewable: 15% by 2020 Clean: 100% by 2045	2020 Energy Mix: Coal: 23% Natural Gas: 27% Hydro: 24% Renewable: 12% Purchases: 14%	None reported	Yes	Yes	80 kW-AC

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San Diego Gas & Electric	CA	Sempra	Clean: 100% by 2045	Net-Zero GHG: 100% by 2050	Renewable: 60% by 2030 Clean: 100% by 2045	2021 Owned/Contracted Mix: Natural Gas: 49% Renewable: 51%	None reported	Yes	Yes	None
Sierra Pacific Power (NV Energy)	NV	Berkshire Hathaway Energy	See Holding Company	Net-Zero GHG Emissions by 2050	Renewable: 50% by 2030 Clean Goal: 100% by 2050	2022 Resource Mix: Coal: 30% Natural Gas: 70%	6 MW in 2023 261 MW in 2025 226 MW in 2028	No	Yes	None
Southern California Edison	CA	Edison Intl.	See Holding Company	Clean: 100% by 2045	Renewable: 60% by 2030 Clean: 100% by 2045	2022 Owned Resource: Nuclear: 21% Natural Gas: 37% Hydro: 32% Renewable: 10%	None reported	Yes	Yes	None
Southern Indiana Gas & Electric Co. (Vectren)	IN	CenterPoint	See Holding Company	Net-Zero GHG emissions by 2035	Clean Goal: 10% by 2025	2021 Owned Resources: Coal: 82% Natural Gas: 13% Renewable: 5%	490 MW in 2023 90 MW in 2025	Yes	Yes	None
Southwestern Electric Power	AR, LA, TX	American Electric Power (AEP)	See Holding Company	Renewable: 50% by 2030 Clean: 80% by 2030 Clean: 100% by 2050	AR: None LA: None TX: Renewable: 5880 MW by 2015; Goal: 10,000 MW by 2025	2021 Owned Resources: Coal: 47% Natural Gas: 48% Renewable: 5%	559 MW in 2023 110 MW in 2025 1,000 MW in 2028	AR: Yes LA: Yes TX: Yes	Yes	None
Southwestern Public Service	NM, TX	Xcel Energy	See Holding Company	Reduce CO2 Emissions: 85% by 2030 Reduce CO2 Emissions: 100% by 2050	NM: Renewable: 80% by 2040 Clean Goal: 100% by 2045 TX: Renewable: 5880 MW by 2015; Goal: 10,000 MW by 2025	2021 Energy Mix: Coal: 28% Natural Gas: 32% Renewable: 40%	759 MW by 2025 546 MW in 2027-30 2,797 MW in 2031-40 334 MW in 2056-58	NM: Yes TX: Yes	Yes	None
Tampa Electric	FL	Emera	See Holding Company	Reduce CO2 Emissions: 60% by 2025 Reduce CO2 Emissions: 80% by 2040 Net-Zero CO2 Emissions by 2050	None	2022 Owned Resources: Coal/IGCC: 35% Natural Gas: 53% Renewable: 12%	395 MW in 2023	Yes	Yes	None
Tucson Electric Power	AZ	Fortis	Renewable: 70% by 2035 Reduce CO2 Emissions: 80% by 2035	Reduce GHG Emissions: 75% by 2035 Net-Zero GHG: 100% by 2050	Renewable: 15% by 2025	2021 Owned Resources: Coal: 34% Natural Gas: 57% Renewable: 9%	423 MW in 2022 387 MW in 2027 406 MW in 2032	No	Yes	None
UNS Electric	AZ	Fortis	See Holding Company	Reduce GHG Emissions: 75% by 2035 Net-Zero GHG: 100% by 2050	Renewable: 15% by 2025	2021 Resource Mix: Natural Gas: 81% Renewable: 19%	None reported	No	Yes	None
Upper Peninsula Power	MI	None	None	None	Renewable: 15% by 2021	Owned Resources: Hydro: 100%	None reported	Yes	Yes	None
Wheeling Power	WV	American Electric Power (AEP)	See Holding Company	Renewable: 50% by 2030 Clean: 80% by 2030 Clean: 100% by 2050	None	2022 AEP Corp Resource Mix: Coal: 41% Nuclear: 7% Natural Gas: 27% Renewables/EE/Hydro: 23%	None reported	Yes	Yes	None

UTILITY CLEAN ENERGY AND RELATED STATISTICS

(Vertically Integrated with Annual Operating Revenues of $10 million or more in the Contiguous 48 States)

Utility Name	State (Electric Service)	Holding Company	Utility Clean/Renewable Electric Energy Commitment/Goal	Holding Company Clean/Renewable Electric Energy Commitment/Goal	State Clean/Renewable Energy Standard/Goal	Energy/Resource Mix	Fossil Capacity Planned for Retirement	Securitization Enabled	Net Energy Metering or RCP Policy	Installed Community Solar Capacity end of 2021
Wisconsin Electric Power	WI	WEC Energy Group	See Holding Company	Reduce CO2 Emissions: 60% by 2025 Reduce CO2 Emissions: 80% by 2030 Clean: 100% by 2050	MI: Renewable: 15% by 2021 WI: Renewable: 10% by 2015 Clean Goal: 100% by 2050	2021 WEC Energy Mix: Coal: 36% Nuclear: 19% Natural Gas: 30% Renewables: 7% Purchases: 8%	496 MW in 2023 616 MW in 2024	MI: Yes WI: Yes	Yes	None
Wisconsin Power & Light	WI	Alliant Energy Corp.	See Holding Company	Reduce CO2 Emissions: 50% by 2030 Exit coal by 2040 Clean: 100% by 2050	Renewable: 10% by 2015 Clean Goal: 100% by 2050	2021 Energy Mix: Coal: 28% Natural Gas: 37% Hydro: 3% Renewable: 18% Purchases: 14%	310 MW in 2022 310 MW in 2023 306 MW in 2024	Yes	Yes	None
Wisconsin Public Service	WI	WEC Energy Group	See Holding Company	Reduce CO2 Emissions: 60% by 2025 Reduce CO2 Emissions: 80% by 2030 Clean: 100% by 2050	MI: Renewable: 15% by 2021 WI:Renewable: 10% by 2015 Clean Goal: 100% by 2050	2021 WEC Energy Mix: Coal: 36% Nuclear: 19% Natural Gas: 30% Renewables: 7% Purchases: 8%	372 MW in 2023 157 MW in 2024	MI: Yes WI: Yes	Yes	None

DIRECT TESTIMONY OF JUSTIN M. JOINER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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ATTACHMENT LIST

Long-Term PPAs in Effect During the Test Year ..... Attachment JMJ-01DR
Long-Term PPAs Executed During the Test Year ..... Attachment JMJ-02DR

DIRECT TESTIMONY OF JUSTIN M. JOINER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Justin M. Joiner. I am Vice President of Resource Management for Arizona Public Service Company (APS or Company). I oversee long-term resource planning and acquisition, wholesale energy market development and engagement, fuel procurement, and energy commodity trading. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. Prior to joining APS, I served as Chief Commercial Lead of Renewable Development and as Director of Power Supply Services at CenterPoint Energy, Inc. I have traded energy in the real-time energy markets, conducted Integrated Resource Plans (IRP), negotiated and acquired generation assets and developed asset maximization strategies for generation fleets in the Midcontinent Independent System Operator (MISO) and PJM Interconnection, the regional transmission organizations (RTOs) that deliver power to much of the Midwestern and Eastern United States. I earned a Bachelor of Science degree in economics and finance, and a Master of Business Administration from Southern Illinois University Edwardsville.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. No, but I have spoken on behalf of APS at Commission Open Meetings. In addition, I have testified before the Indiana Utility Regulatory Commission on behalf of CenterPoint Energy in rate cases, fuel adjustment matters, and Certificate of Public Convenience and Necessity proceedings.

II. SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss how APS plans to fulfill the critical resource needs of its customers for the foreseeable future. My testimony will discuss how APS's strategy of procuring new resources—in particular clean energy generation and storage technologies—coupled with continued exploration of the opportunities offered by further western regional energy market integration will meet these critical resource needs. In addition to these topics, my testimony will also address several other critical resource planning and procurement topics. These topics include the balancing of considerations that factor into APS decisions as to whether a resource should be procured via power purchase agreements (PPAs) versus acquired as a Company owned and operated resource; fuel and purchased power expense management (e.g., through natural gas hedging); and APS's position as it relates to the current AG-X commercial and industrial customer electricity buy-through program, along with certain proposed modifications to the program's structure.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. APS has been investing in a balanced portfolio of generation resources necessary to support the Company's rapidly growing customer base and ensure year-round service reliability. While the Company is actively pursuing an "all of the above" resource procurement strategy to provide a balance of diverse owned and contracted resources for customers, APS is focused on delivering electricity from safe, reliable, and clean generation resources.

Across western electricity markets, utility companies are facing serious resource deficiencies in the coming years. For APS, these challenges are coupled with rapidly growing customer load and extreme weather events that in recent summers

have strained electric grids across the Western United States. Broadly speaking, APS has a strategy to ensure the continued delivery of safe, reliable, and clean resources to its customers: First, over the long term, greater western market integration will benefit APS customers through improved efficiencies and resource optimization; and second, in the nearer term, APS's plans for resource procurement offer a balanced approach to procure affordable and reliable resources for APS customers that offer them greatest long-term value. I discuss the benefits of clean energy resources, including resource cost competitiveness, enhancements to APS's resource diversity and stability, protections for APS's customers from fuel price volatility, and preservation of APS's access to low-cost capital, among others. In addition, because of substantial customer demand for these resources and APS's high solar resource potential, these investments help create tremendous economic growth opportunities within APS's service territory.

In addition to these resource management and acquisition strategies, APS is also continuing its aggressive strategies to mitigate—and hedge against—the impacts on customers from purchased fuel and power. Given the high volatility of present market conditions, and the globalized external drivers for those conditions, these strategies are essential to ensuring that APS electricity rates remain affordable.

Finally, my testimony discusses the Company's proposed changes to its AG-X program, which is APS's electricity buy-through program for larger commercial and industrial customers with an aggregated peak load of ten megawatts (MW) or more. This proposal is focused on ensuring resource adequacy and reliability and is intended to alleviate program cost shifts for non-participating APS customers.

III. RESOURCE MANAGEMENT: PLANNING AND PROCURING

A. *Meeting the Needs of APS Customers*

Q. WHY IS A DIVERSE MIX OF ENERGY TYPES IMPORTANT?

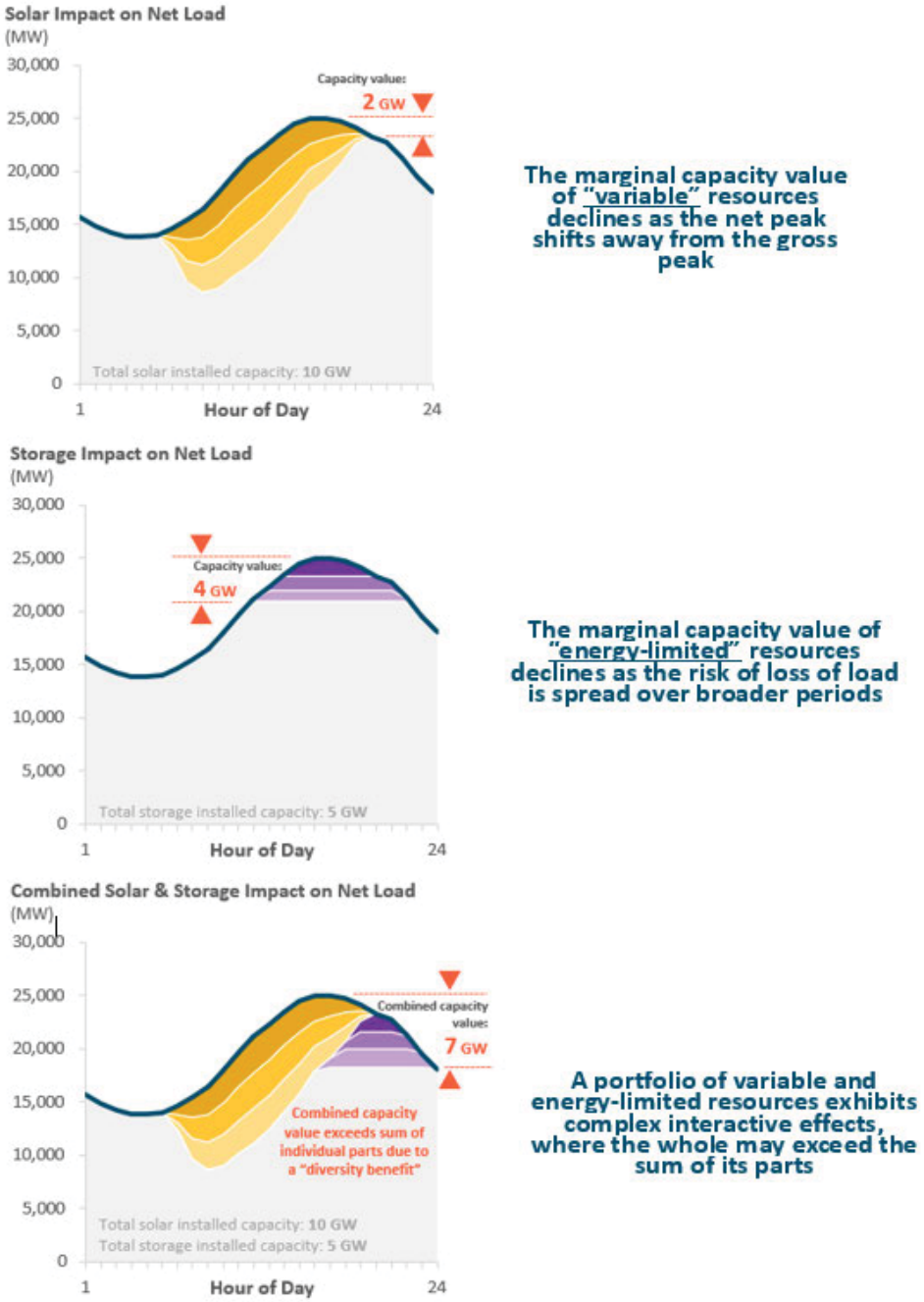
A. Resource diversity reinforces affordability, reliability, and energy security by limiting risk factors that impact specific resource types. A diverse energy mix helps ensure affordability through a balanced portfolio that hedges against commodity and price volatility of generation resources. The not-too-distant events of Winter Storm Uri in February 2021 and its impacts on natural gas supplies and prices are a perfect example. Additionally, recent supply chain constraints impacting the development of solar and energy storage projects, coupled with higher than forecasted natural gas prices, are a current reminder of the value of having additional resources to lessen the cost impact and dependency of a single resource type. During this period, coal and nuclear have been stable in cost and have mitigated the cost impacts of gas prices while ensuring reliable baseload energy.

A diverse generation fleet that includes natural gas, nuclear, solar, wind, energy storage, and other resources will enable APS's generation fleet to be resilient from supply chain disruptions, weather patterns, and market conditions. Events impacting energy supplies could involve a number of different factors, such as scarcity pricing in fuel, chemicals, water supplies, or other electricity generation inputs. Weather patterns can limit solar and wind generation output. Ensuring resource diversity provides a hedge against these and other events to preserve service reliability for customers.

In addition, a balanced and diverse resource portfolio ensures resources complement each other to enhance the performance of the generation fleet. For

example, the images in Figure 1 illustrate how combining solar and storage can produce a bigger capacity benefit together than as separate resources.[1]

Figure 1. Solar and Energy Storage Capacity



[1] *Resource Adequacy in the Desert Southwest*, Energy and Environmental Economics (Feb. 2022), p. 3.

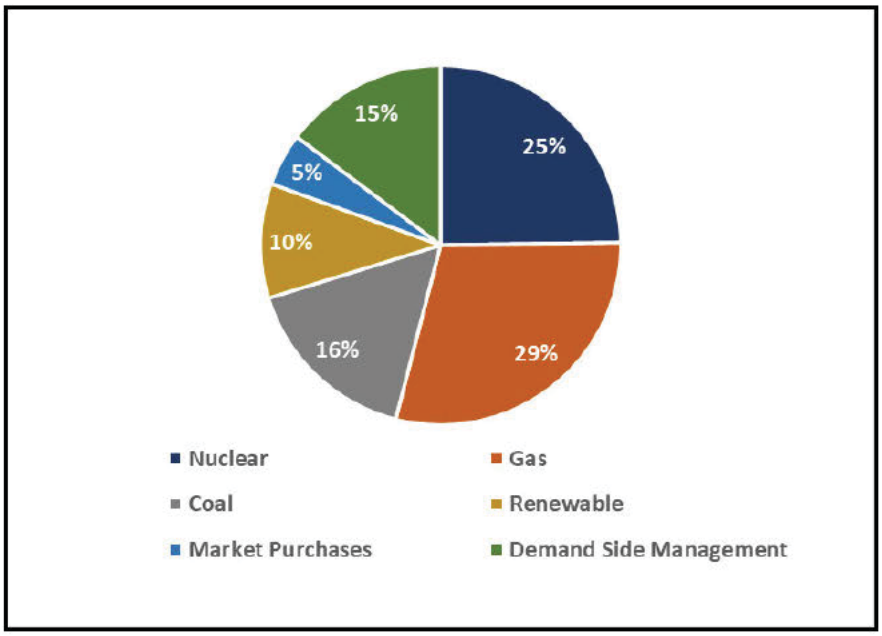
Similarly, all resource types have specific characteristics that APS considers to ensure a stabilized grid. For instance, synchronous resources that have reactive and dispatchable capabilities provide frequency response for APS's transmission and distribution systems. As such, by maintaining a diverse fleet of resources, APS can optimize their performance with one another to maximize value to customers.

Q. PLEASE DESCRIBE APS'S CURRENT RESOURCE MIX.

A. APS serves customers' energy needs with a diverse mix of energy resources, both utility-owned and contracted (e.g., through a PPA). As demonstrated in Figure 2, APS's resource mix includes nuclear, coal, natural gas, renewables, short-term purchases, and demand-side management (energy efficiency and demand response) programs. Among APS's current portfolio of nuclear, renewable, and energy efficiency plus demand response resources, the Company's generation portfolio is 50% clean today.

Figure 2. APS's 2021 Generation Resource Mix

(% of Generation Serving Own Load)

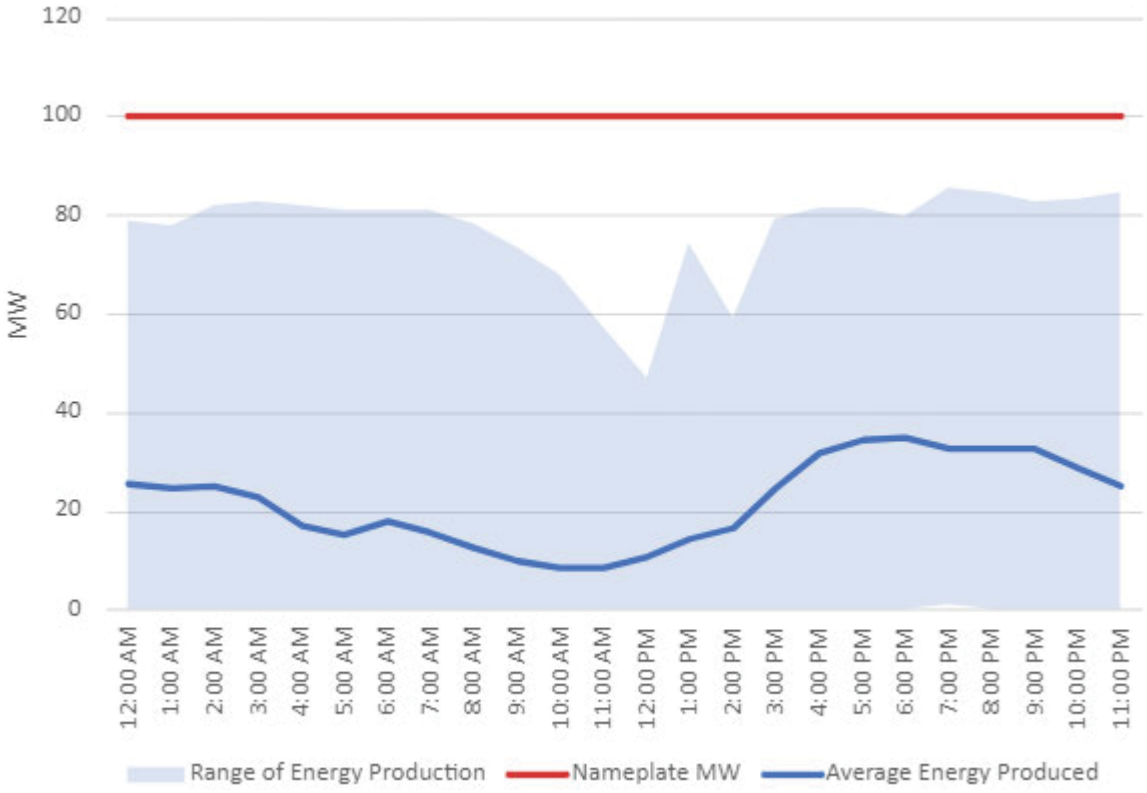


Q. WHAT IS THE DIFFERENCE BETWEEN ON-PEAK RESOURCE CAPACITY AND NAMEPLATE RESOURCE CAPACITY?

A. The nameplate rating is the amount of energy the resource is capable of providing at a given time under optimal conditions. However, ambient conditions, limits in dispatchability, weather conditions, duration, snapback,[2] or other resource-specific conditions may exist that reduce a given resource's capability to actually provide the nameplate amount of capacity. As such, when APS evaluates the capabilities of available resources, the Company takes into consideration the conditions that would limit a resource's optimal output. APS then further evaluates the actual production of the resource against the Company's summer system peak periods, which results in an accredited "On-Peak MW" value for the resource and provides a more realistic measure of the resource's actual capacity value. As an example, Figure 3 illustrates the difference between the average energy produced at an APS wind resource and its nameplate capacity, along with the range of energy produced. This evaluation is essential for APS to ensure there are sufficient resources to serve customers during peak conditions.

[2] Snapback refers to increases in system demand after a resource is called. A common example is demand response that may have a resource benefit by turning up the thermostat temperature in a customer business or home resulting in less energy demand during a period of critical system need and subsequently using more than normal energy amounts to restore the temperature in the home or business during a later, less critical time of system need.

Figure 3. July 2021 Wind Resource Performance



Q. PLEASE EXPLAIN THE RESOURCE DIVERSITY BENEFITS OF NATURAL GAS RESOURCES AND RENEWABLE RESOURCES.

A. Natural gas resources play an important role in meeting the needs of APS's customers, especially as APS works to incorporate more renewable resources into its resource portfolio. Solar and wind energy resources fluctuate generation output throughout the day based on changing weather patterns, limiting their value to energy and not capacity. For example, solar production may change quickly when cloud cover moves in, and when the sun rises or sets. To ensure continued and reliable service for APS's customers, it is vital that the Company have a variety of dispatchable, fast-ramping generation resources that can match energy production and delivery minute-by-minute with customer demand. Natural gas facilities provide very-high-capacity value and can match energy production to meet changing load needs throughout the day. These shifts will only become more

volatile as more intermittent, renewable resources are integrated onto the Western Interconnection.

Figure 4 shows the output from APS's Red Rock Solar Plant on September 8, 2022 and demonstrates the intermittent nature of that resource type. Due to their ability to increase or decrease output at a moment's notice, natural gas plants are key resources in responding to these quick changes in renewable output and operating a reliable and resilient grid as more renewable resources are integrated onto the system.

Figure 4. Output from APS's Red Rock Solar Plant on September 8, 2022

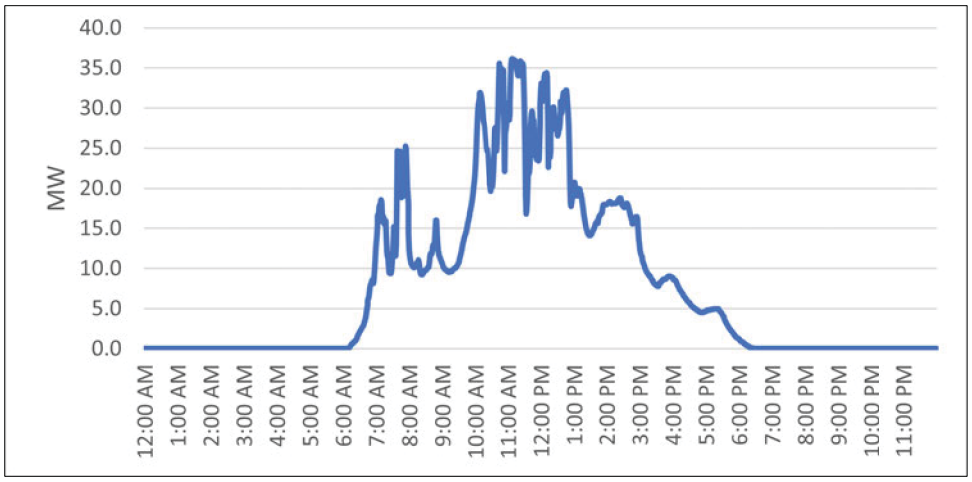
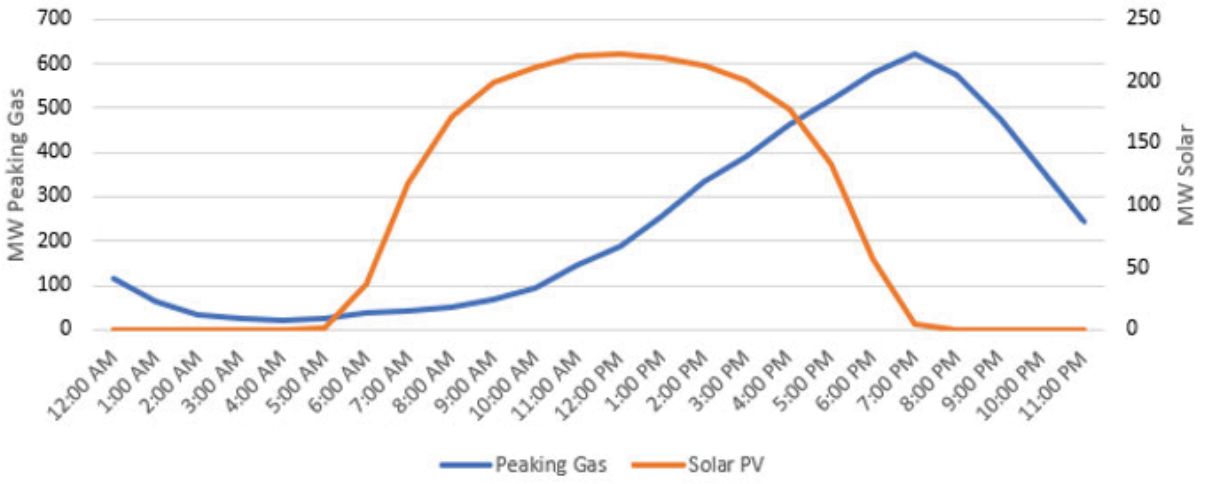


Figure 5 illustrates APS's average utilization of solar energy and peaking gas resources. The peaking gas resources ramp up, or increase production, to maintain reliable service for APS's customers when the sun sets and solar resources are no longer producing output but APS's system is still experiencing high demand. The flexibility of gas resources allows the Company to utilize solar generation to meet portions of its customer's peak energy needs and continue reliable service after sunset.

Figure 5. Average July 2021 Resource Utilization with Volumes Scaled to Each Other



Energy storage resources can provide renewable balancing support similar to that provided by natural gas resources. However, limited storage duration impacts the ability of the energy storage resources to meet peak capacity needs. New resource technologies, including longer duration energy storage technologies, are evolving. That said, given the cost and maturity of these new technologies, natural gas resources continue to be essential in ensuring reliable service as the Company transitions to a clean energy future while providing the desired fleet diversity and planning hedge discussed earlier in my testimony.

Q. PLEASE DESCRIBE THE ANTICIPATED RESOURCES NEEDED TO SERVE APS CUSTOMERS AND THE MAJOR DRIVERS FOR THOSE NEEDS.

A. APS is experiencing significant demand growth across the Company's service territory. The Company's 2020 IRP indicates that APS is adding 20,000-22,000 customers per year, resulting in peak load requirement growth of over 1,100 MW between 2022 and 2026; however, customer-sited resources (energy efficiency, customer-sited solar, and demand response) are expected to reduce the amount of peak load that APS serves by over 400 MW during that same period. As

demonstrated from APS's 2020 IRP, the load forecast combined with the retirement of the Cholla Power Plant (currently providing 387 MW of generation) no later than April 2025 and the concurrent expiration of several third-party PPAs (currently providing approximately 700 MW of peaking capacity) establish the baseline need for almost 2,300 MW of additional on-peak resource capacity by 2026.

Q. DO YOU ANTICIPATE ADDITIONAL RESOURCES BEYOND WHAT WAS DESCRIBED IN THE 2020 IRP?

A. Yes. APS's updated forecast for load growth through 2026 is approximately 1,400 MW, which is about 300 MW higher than the 2020 IRP. The updated forecast is the result of substantial customer growth, including large technology and manufacturing facilities siting in the APS service territory.

B. *Regional Conditions*

Q. WHAT HAVE BEEN THE RECENT CONSEQUENCES OF RESOURCE CONSTRAINTS ACROSS THE WESTERN UNITED STATES?

A. The Southwest region continues to experience resource constraints in peak seasons due to customer growth and the related increases in electricity demand, baseload and other thermal resource retirements, and extreme weather events, such as heat and drought conditions. These challenges have been highlighted over the past three summers with repeated Emergency Energy Alert (EEA) Level 3 emergencies declared across the Western United States balancing authorities. Such declarations arise when there is an inability within a balancing authority to meet minimum contingency reserve requirements and load interruption is imminent or in progress.

Most recently, a heat wave challenged the western electric grid during September 2022, and, again, EEA Level 3 emergencies were declared across the West, and public appeals to reduce energy use were issued to California customers. Through

prudent planning to ensure appropriate generation reserves were available, APS was able to continue to provide service throughout this heat wave, and, in fact, APS resources were utilized to assist neighboring jurisdictions suffering resource shortages. That said, portions of energy from market participants to AG-X customers were curtailed during each of these events, but APS was able to ensure continuous service to these customers. Nevertheless, these events continue to highlight regional needs for resource adequacy.

Q. WHAT IMPACTS HAVE REGIONAL CONDITIONS HAD ON APS CUSTOMERS?

A. While neighboring regions have experienced generation reserve and capacity events, some leading to rotating blackouts, APS has been able to ensure that energy is available when customers need it. APS resources are dedicated to the reliability of customers including during emergency events and thus meet the criteria for resource adequacy. As observed over the past three summers, energy from the wholesale market cannot be relied on to meet customer needs on days of regional grid stress.

APS generation resources have performed well through the extreme heat of the past two summers. In the summer of 2022, APS had a 95% Equivalent Availability Factor for its thermal generation resources and 99.8% success when APS called a resource online. This means APS's generation fleet has been available when needed 94.4% and 99.8% of the time the past two summers when called upon. In the face of unprecedented summer heat conditions—where 2020 was the hottest Arizona summer ever recorded and similar conditions have persisted since—the combination of generation resource and transmission performance, along with thoughtful resource planning, has allowed APS to continue providing reliable service.

However, regional constraints, limited generation supply, and other factors are causing APS's customers to experience increased fuel and purchased power prices. APS continues to take action to mitigate price fluctuations through a fuel hedging program, a competitive procurement process, and participation in the wholesale market to find economic solutions.

Q. PLEASE DESCRIBE APS'S PARTICIPATION IN REGIONAL ENERGY MARKETS.

A. APS participates daily in both the wholesale bilateral market and the Western Energy Imbalance Market (EIM). APS engages the bilateral markets for both capacity-backed products that meet the characteristics of resource adequacy and economic energy. The Company engages in the bilateral market to identify available bulk power purchases at the lowest possible cost from its peer utilities and to maximize the value of APS's generation fleet. The Western EIM, on the other hand, is an automated trade platform that helps balance fluctuations in variable generation and ensures the most cost-effective use of resources to meet load needs among the participating entities. As to both, customers receive the benefits from this market activity through lower energy costs, and off-system sales go back to APS's customers. For example, the Western EIM estimates that APS customers have saved over $266 million in fuel and purchased power costs through its lifetime participation in the EIM as of the end of the second quarter of 2022.

Q. CAN APS RELY ON EXISTING WHOLESALE MARKETS ALONE TO MEET CUSTOMER NEEDS?

A. No, APS cannot rely on wholesale markets to meet customers' needs reliably and affordably. Resources that are not already dedicated to another entity for resource adequacy purposes (i.e., the other entity would have priority to use the resource in emergency conditions) are scarce, which increases costs to customers. Resources without resource adequacy, such as those identified through spot-market

purchases, have no guarantee of delivery. As such, overreliance on purchases from these markets to serve customers would put reliability at risk.

Q. IS APS EXPLORING MORE INTEGRATED REGIONAL MARKETS OR REGIONAL TRANSMISSION ORGANIZATIONS? IF SO, WHY?

A. Yes. Participation in broader markets has the potential to enhance future customer reliability, capture customer cost savings, and more efficiently integrate clean energy resources via potential regional generation and transmission planning. APS is exploring three types of regional arrangements that could assist the Company in achieving these goals, including: (1) regional resource adequacy constructs, which require adequate levels of asset backed resources and enables sharing of those resources, (2) day-ahead markets, which optimize generation dispatch over a broad geographic area that provide production cost savings from a shared resource adequacy construct, and (3) RTOs, which include resource adequacy constructs and day-ahead markets and also provide regional transmission planning. APS is evaluating these potential regional constructs to ensure the appropriate market rules and governance structures are in place to deliver benefits for customers.

C. *Resource Planning and Procurement*

Q. HOW DOES APS PLAN FOR FUTURE RESOURCE NEEDS?

A. Every three years APS develops an IRP, which is a 15-year plan based on forecasted loads and resources necessary to serve customers. The load forecast is informed by weather data, customer usage, economic forecasts, population changes, electric vehicle adoption rates, and building trends, among other factors concerning load growth within APS's service territory. APS plans for total energy as well as peak system needs. Peak system needs are met with generation capacity, which is the maximum amount of generation output that can be expected from a certain resource during peak periods based on generator characteristics and past unit performance.

APS studies several potential resource portfolios. Portfolio analysis focuses on optimizing the total costs necessary to serve customers, taking into account capital, maintenance, fuel, and other expenses. APS identifies total capacity and energy needs within the IRP, and an action plan is proposed for the next five years. The action plan proposes the number and type of resources that will be necessary. The Company then issues a request for proposals (RFP) for the specific resource needs identified in the IRP and evaluates the proposals based on a number of quantitative and qualitative factors.

Q. WHAT IS THE RESOURCE PLANNING ADVISORY COUNCIL?

A. The Resource Planning Advisory Council (RPAC) was developed in early 2021 as a diverse set of stakeholders to partner with APS in the development of the Company's 2023 IRP. Stakeholders represent consumer advocacy groups, public interest groups, environmental advocates, and industry. APS has found benefit in the feedback of RPAC members and has since expanded the purview of the group to include providing input on the Company's 2022 All-Source RFP. Small stakeholder working groups reviewed and commented on the RFP structure, bidding criteria, and evaluation methodology. Many of their comments were incorporated into the final document.

Q. PLEASE DESCRIBE APS'S ALL-SOURCE RFP PROCESS.

A. APS issues All-Source RFPs to ensure the most cost-effective and reliable options are selected to meet the growing power needs of its customers. An All-Source RFP is open to expansive types of technologies including demand-side resources. An independent monitor is used to support the administration and evaluation of responses to the All-Source RFP. The All-Source RFP provides the capacity amount and in-service dates requested by APS, and any entity who registers for the third-party platform may submit a response to the request. The RPAC discusses and provides input on the All-Source RFP, including scoring criteria which informs

APS's decision on the selected resources. The RFP process can result in a resource that is owned by the Company or a resource owned by a third party where APS enters into a PPA.

Q. WHAT IS A PPA AND HOW DOES APS USE THESE AGREEMENTS?

A. PPAs are contracts for energy, capacity, flexibility products like ancillary services, and most attributes associated with the generation of energy from the facility. APS leverages various PPAs to provide energy and capacity to its customers.

Q. WHAT FACTORS ARE TAKEN INTO ACCOUNT WHEN COMPARING POWER PURCHASE AGREEMENTS AND UTILITY-OWNED RESOURCES?

A. APS performs an analysis of costs and benefits of proposed PPAs and utility-owned resources to determine which projects are selected for shortlist and negotiation, and ultimately procured. When comparing resources owned by the utility and those acquired through a PPA, APS considers numerous factors, which include but are not limited to: (1) differences in contract duration versus the resource's useful life, (2) near and long-term pricing implications (e.g., managing risks as to mature versus emerging technologies), (3) timing and cost structure, (4) material and construction quality and potential long-term operating and cost impacts, (5) location optimization for interconnection and other resource needs (6) end of life asset value (e.g., transmission and interconnection assets), and (7) impact to the Company's balance sheet for contractual obligations made on behalf of APS's customers with a third party. In conducting competitive All-Source RFPs, APS takes these and other considerations into account when evaluating submitted proposals with the aim of creating a balanced portfolio of owned versus contracted resources.

As such, when APS evaluates whether to procure an owned resource versus a resource subject to a PPA, APS takes these and other critical considerations into account so that options can be evaluated on a level playing field. Ultimately, by critically evaluating these considerations during resource procurements, APS can further diversify its fleet of generation resources and customers will see greater value with a balance of owned versus contracted resources.

Q. PLEASE IDENTIFY EACH LONG-TERM PPA THAT WAS IN EFFECT DURING THE TEST YEAR.

A. Attachment JMJ-01DR is a chart identifying each agreement that was in effect during the Test Year.

Q. DID THE COMPANY ENTER INTO ANY NEW LONG-TERM PPAS DURING THE TEST YEAR?

A. Yes. Attachment JMJ-02DR identifies each agreement APS executed during the Test Year and includes the date the resource is anticipated to begin serving APS customers.

Q. WERE EACH OF THESE AGREEMENTS PROCURED USING THE RFP PROCESS YOU DESCRIBED EARLIER?

A. Yes. Each of these agreements help fulfill a critical resource need that was identified either through the Company's long-term planning process or was procured in compliance with the Commission's Renewable Energy Standard. Each agreement was thoroughly reviewed to ensure that it would be cost-effective and provide value to APS customers.

A copy of the pertinent RFPs, summaries of the responses, and the contracts will be provided in APS's initial set of discovery responses, subject to appropriate confidentiality protection.

Q. ARE THESE LONG-TERM AGREEMENTS PRUDENT?

A. Yes, absolutely. These agreements are prudent when considering all relevant conditions at the time these resource decisions were made.

D. *Developing a Cleaner, More Secure Energy Supply for the Future*

Q. WHY IS APS INVESTING IN RENEWABLE ENERGY AND ENERGY STORAGE RESOURCES?

A. Utility-scale renewable generation and energy storage resources provide a range of benefits for APS customers and Arizona. Most importantly, over the long term, these resources present the greatest value option for customers as the Company evaluates the cost of energy, cost of capacity, deferred investment, and operational characteristics through competitive procurement (based on current RFP results). Additionally, these investments attract large commercial customers and associated economic growth to Arizona, leverage tax incentives that help further reduce their overall cost, align with the priorities of major lenders and investors to reduce capital costs for APS (such as environmental, social, and governance (ESG) policies), and contribute to a diverse resource mix that is currently balanced by mostly thermal and baseload generation.

Q. PLEASE FURTHER DESCRIBE THE ECONOMIC BENEFITS OF CLEAN RESOURCES.

A. While over the near and mid-terms dispatchable resources such as natural gas will continue to provide necessary capacity support, clean resources present cost-effective alternatives to conventional thermal resources, and such resources provide the greatest value for customers over the long term. Because renewable and energy storage resources have already proved to be cost-competitive within APS's RFP process, the Company anticipates that as new resources are acquired, more renewable and energy storage resources will be integrated into APS's resource mix. The economics of renewable and storage resources are further

strengthened by federal tax credits that lower the overall cost of investment for customers. Through the Inflation Reduction Act of 2022, as tax credits are implemented, the economic performance of renewable and energy storage resources will continue to improve. Additionally, as APS witness Andrew Cooper describes in his testimony, ESG criteria increasingly determines APS's access to affordable capital.

Q. PLEASE EXPLAIN THE IMPORTANCE OF INCORPORATING CLEAN RESOURCES INTO A DIVERSE RESOURCE PORTFOLIO.

A. Once developed, renewable and energy storage resources are not subject to the same supply and demand issues associated with resources that require fuel purchases on an open, globalized market, making this type of generation incredibly valuable from a resource diversity standpoint. Renewable and storage resources provide an ideal alternative to resources that are subject to fuel supply shortage and pricing issues that can impact conventional thermal resources, such as the supply constraints arising from Winter Storm Uri in February 2021 that were previously discussed. Operationally, the combination of energy storage with renewable resources allows APS to take full advantage of renewables by storing the energy when it is in excess and the value of energy is low, and then redeploying that energy when customers need it, thus avoiding purchasing energy during high-priced periods. Storage combined with solar acts as an arbitrage by charging when prices are low and discharging when prices are high. Additionally, storage with solar presents little to no variable costs and thus provides rate stability and predictability. As such, by balancing the Company's resource portfolio with renewable and energy storage resources, APS can minimize fuel price volatility for its customers and enhance Arizona's energy security.

Q. ARE THERE ADDITIONAL ECONOMIC DRIVERS FOR INVESTING IN CLEAN RESOURCES?

A. Yes, clean energy remains an important consideration for new commercial customers looking to bring investment to Arizona. Many of APS's large commercial and industrial customers have expressed a desire to be served by carbon-free generation and include these considerations as key factors in their operational and business site selection decisions. In fact, through the Company's Green Power Partners program, APS has partnered with customers interested in advancing renewable energy that are willing to pay a premium for these resources that serve as an offset against overall customer costs under the Company's Renewable Energy Adjustment Charge. This program recovers the incremental costs associated with pricing drivers for customer-focused clean energy resource investments, which prevents these costs from being passed on to APS's customer base while accelerating affordable investment in clean energy.

As customer interest in clean energy resources continues and APS procures additional renewable and energy storage resources, Arizona should be well-positioned to benefit from more local jobs and commerce.

Q. WHAT IS THE COMPANY'S PLAN FOR INVESTING IN CLEAN ENERGY AND ENERGY STORAGE?

A. As discussed in APS's recently acknowledged 2020 IRP,[3] APS expects to invest in new wind, photovoltaic solar paired with energy storage (PVS), and stand-alone energy storage projects by 2026. When combined with access to microgrid resources, natural gas tolling agreements, and customer-side resources such as energy efficiency and demand-side management, these resource investment plans are designed to meet the Company's need for on-peak resource capacity by 2026.

[3] Docket E-00000V-19-0034, Decision No. 78499 (March 2, 2022).

APS refreshes the IRP every three years, and Figure 6 provides an estimate of how APS may meet its capacity requirements based on the 2020 IRP assumptions. Actual procurement will be obtained through an All-Source RFP process, and the actual amounts of solar, wind, PVS, and stand-alone storage may differ from the amounts shown in Figure 6.

Figure 6. Anticipated Annual Renewables and Energy Storage Procurements through 2026 (MW)

	2023	2024	2025	2026	Total
Wind	233	0	150	0	**383**
PVS	210	215	813	200	**1,438**
Energy Storage	200	200	0	0	**400**
Total MW	643	415	963	200	**2,221**

For needs beyond 2026, the Company continues to explore all options through its All-Source RFP process and long-term planning. As noted in the 2020 IRP, APS expects to increase its resource capacity by approximately 17,000-25,000 MW between 2020-2035.

IV. FUEL AND PURCHASED POWER EXPENSE

A. *Cost Management*

Q. HOW DOES APS MANAGE ITS FUEL AND PURCHASED POWER EXPENSE?

A. APS employs a variety of strategies to manage fuel and purchased power costs. I highlight several of these strategies below.

- As described earlier in my testimony, the Company uses a competitive RFP process for new resources. This process is overseen by an independent monitor to ensure a fair process. Additionally, APS engages with the RPAC for broader stakeholder feedback and collaboration in the RFP process.

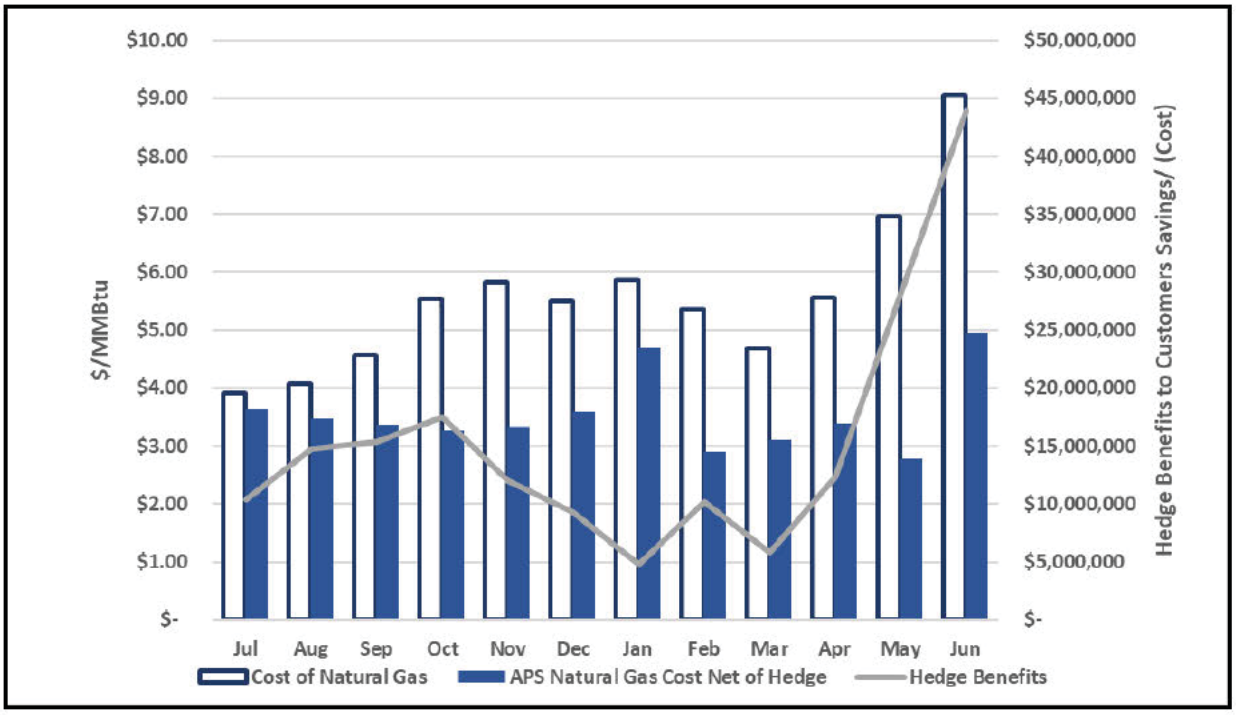
- APS owns and contracts for a diverse mix of resource types, which helps limit risk and significant cost changes associated with a single resource type. In this respect, APS can optimize and rebalance customer needs across resource types to maintain reliability and the lowest possible costs for customers.
- APS uses an advanced optimization software tool to ensure customer reliability with the most economical generation resource dispatch. The Company also leverages the expertise of marketing and trading analysts who optimize resource decisions in real time and over longer time horizons on behalf of customers.
- APS participates in both the wholesale bilateral energy market and the Western EIM on a continuous basis, and savings from these efforts are passed along to customers through the Power Supply Adjustment (PSA).

Additionally, as part of its overall fuel management strategy, APS uses financial instruments (hedges) to reduce customer exposure to commodity prices.

Q. HOW DOES HEDGING HELP APS MANAGE FUEL PRICES?

A. Fuel supply hedging mitigates impacts of short-term fuel cost volatility and provides gradualism for long-term industry changes. Generally, APS hedges fuel prices starting three years in advance. The percentage of hedged natural gas escalates annually; currently, 85% of customers' forecasted need for natural gas is hedged one year in advance. While price stability is the primary goal of a fuel hedging program, APS passed along to its customers through the PSA a total of $184.6 million in savings attributable to its hedging program in the Test Year by procuring natural gas at far lower prices than realized.

Figure 7. Realized Natural Gas Price Savings in Test Year Due to Hedging Program



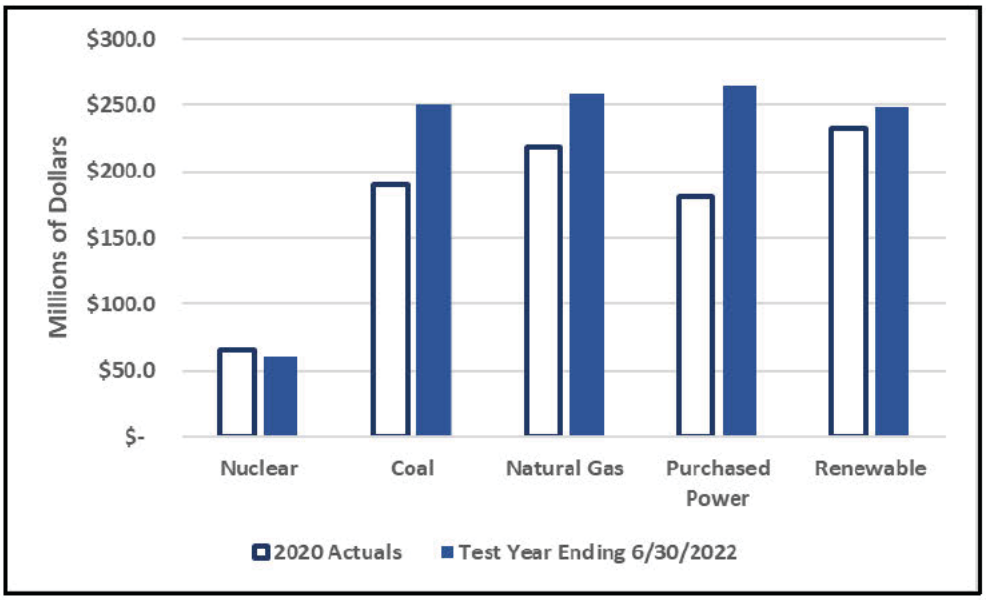
As of August 31, 2022, the Company's hedging program is expected to save customers $338 million related to natural gas prices in 2022 and approximately $221 million in 2023.

B. *Recent Price Increases*

Q. PLEASE DISCUSS THE RECENT INCREASES IN FUEL AND PURCHASED POWER COSTS EXPERIENCED BY APS.

A. The overall cost of fuel and purchased power has increased dramatically over the past two years since the Company's current base cost of fuel was calculated. Figure 8 below shows the difference in APS's fuel and purchased power expense (F&PP) between calendar year 2020 and the Test Year.

Figure 8. 2020 F&PP Expense vs. Test Year F&PP Expense

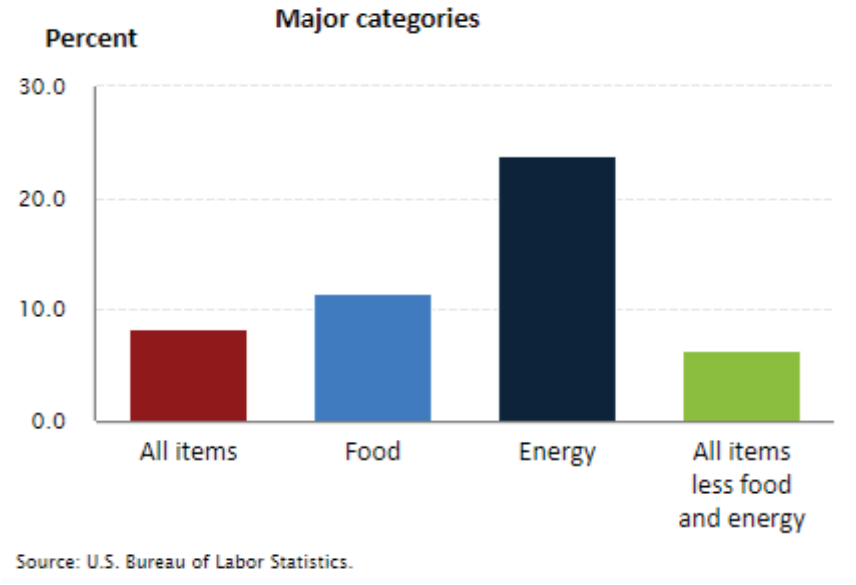


In addition to the impacts of natural gas prices, market purchased power costs, and long-term purchased power costs, the following factors are placing upward pressure on APS's current and expected fuel and purchased power expense over the next few years:

- The global demand for raw materials necessary to support new renewable resource production is increasing worldwide, while supply chain issues due to the COVID-19 pandemic have increased the scarcity and cost of those materials, as has the U.S. Department of Commerce investigation of solar panel pricing.
- The Southwest region continues to grow, bringing increased demand for electricity. Arizona's population, businesses, and industries in the APS service territory are growing while the cost for fuel and purchased power is increasing.
- Fuel costs have increased due to the geopolitical instability in Europe, with reduced supply available for export, while the global demand for natural gas continues to grow.

- As seen in Figure 9 below, while the U.S. inflation rate rose to 8.3% over the 12 months ending August 2022, the cost of energy rose by 23.8% according to the U.S. Bureau of Labor Statistics Consumer Price Index.[4]

Figure 9. 12-Month Percentage Change in Consumer Price Index for Selected Categories – August 2022 (not seasonally adjusted)



All these factors have combined to create a substantial increase in the cost of fuel and purchased power for APS over the past two years.

Q. PLEASE DISCUSS THE IMPACT OF NATURAL GAS PRICE INCREASES TO APS AND ITS CUSTOMERS.

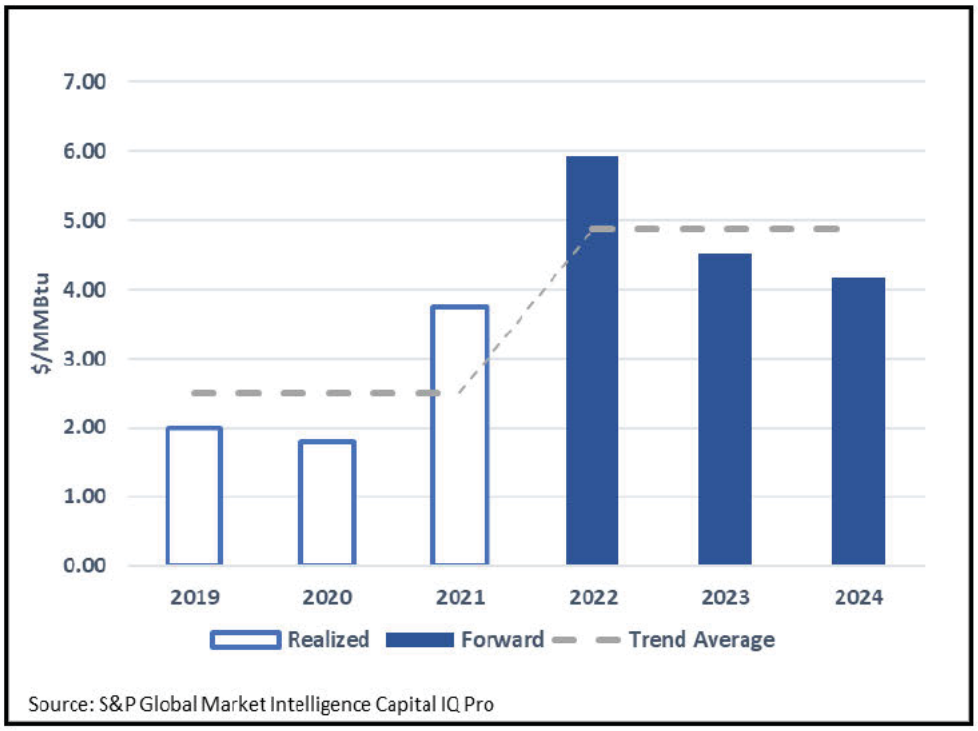
A. The increase in natural gas prices seen over the last two years is in response to several current market conditions discussed earlier in my testimony. For utilities throughout the United States that are expanding renewable resource portfolios, quick-start, natural gas-fired generating units remain a critical part of managing the

[4] U.S. Bureau of Labor Statistics, Consumer Price Index Home Page, accessed September 21, 2022 at https://www.bls.gov/cpi/.

intermittent nature of solar and wind resources, which is also increasing the demand for reliable sources of natural gas.

The San Juan Basin supplies approximately 80% of the natural gas used in the Company's generating units. The realized annual average price of San Juan natural gas in 2019 was $2.00/MMBtu. In contrast, as shown in Figure 10 below, the realized annual average price of San Juan natural gas in 2021 was $3.75/MMBtu, and the annual average price in 2022 is expected to increase even further to $5.93/MMBtu (an increase of more than 196% from 2019 prices) before leveling out in 2024. Based on current market forecasts, increased natural gas prices throughout the Southwest are expected to persist for several years.

Figure 10. Annual Average Natural Gas Prices at San Juan Basin



Q. IS APS TAKING ANY STEPS TO MITIGATE ITS NATURAL GAS EXPENSE?

A. Yes. In addition to the cost management strategies I described above, including an ongoing natural gas hedging program, the Company continually evaluates pricing and availability of natural gas supply to determine if a change in fuel acquisition protocols, generating unit availability, and resource diversity and strategy changes, such as generation dispatch priority, will mitigate overall fuel costs to its customers.

An excellent example of a change resulting from this type of evaluation is the June 2021 agreement between the joint owners of the Four Corners Power Plant (Four Corners) to assess the feasibility of conducting seasonal operations at the plant on an annual basis. Under seasonal operations, one generating unit would be shut down during seasons in which demand for electricity is reduced, subject to market conditions, allowing customers to benefit from both the summer capacity and reliability the plant provides and from lower fuel and power prices if they are less expensive than producing electricity at the plant.

Q. IS APS PLANNING TO PURSUE SEASONAL OPERATIONS AT FOUR CORNERS IN THE FALL OF 2023?

A. No, not at this time. The key driver behind APS's decision to forego seasonal operations in 2023 is the increased volatility and higher prices in the natural gas market that I described above. Dispatching both Four Corners generating units throughout the coming year will shield customers from a portion of the cost impact of higher natural gas prices that are expected to continue through 2023 and into 2024.

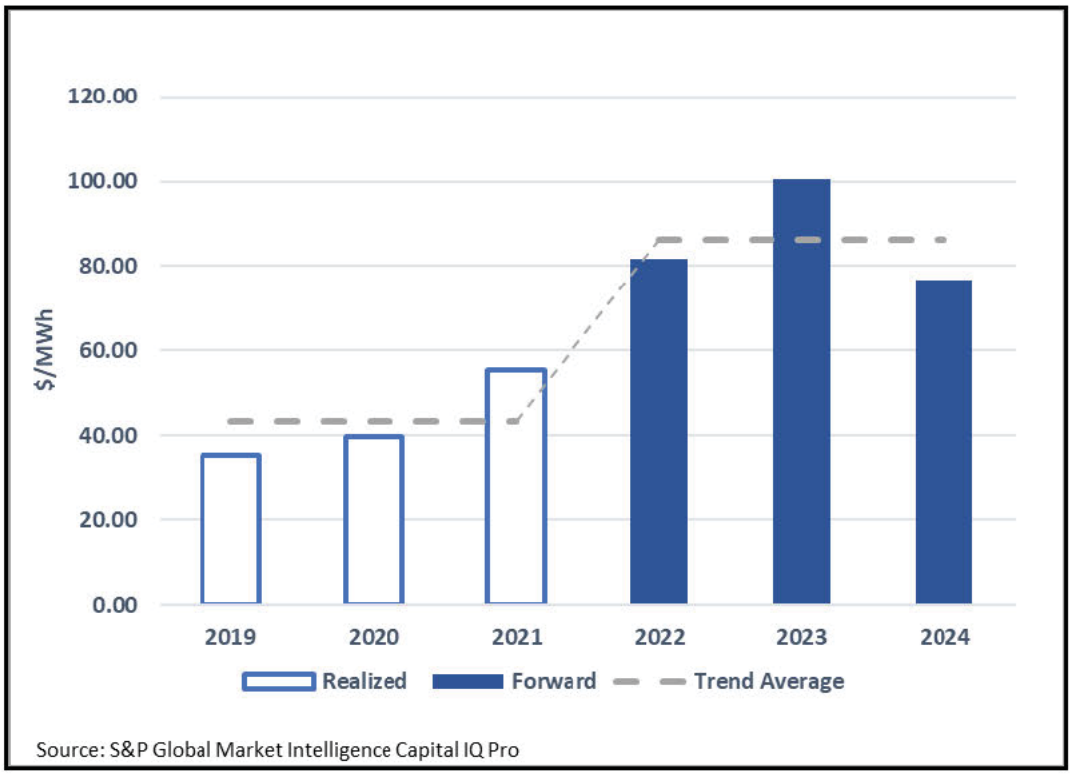
The flexibility built into the agreement between the Four Corners owners that allows for seasonal operations to be determined on an annual basis is an important tool in the Company's fuel cost management strategy, providing APS with the ability to pass along fuel price savings to customers based on market conditions. As APS transitions toward greater reliance upon clean energy resources, the Company's diverse portfolio of generation—including coal-fired generation over the near term—will remain critical to ensuring customer affordability.

Q. HOW HAVE INCREASED PURCHASED POWER PRICES IMPACTED OVERALL FUEL EXPENSE?

A. Purchased power costs have increased in the short-term and mid-term markets due to the limited availability of resource capacity in the Western region and the increased cost of natural gas. The firm, or asset-backed, resources APS needs to purchase to provide reliable power to its customers are being sold at premium prices—when they are available—due to basic supply and demand principles.

The price of purchased power at the Palo Verde market hub is a good indicator of the cost of available energy in the Southwest. Figure 11 below shows that the price for on-peak power delivered at Palo Verde has increased from an annual average of $35.26/MWh in 2019 to an annual average of $58.25/MWh infirm the Test Year, an increase of 57%. Moving forward, prices in 2023 are expected to reach an annual average of $100.56/MWh, an increase of more than 185% since 2019.

Figure 11. On-Peak Market Purchase Prices at Palo Verde Market Hub



Given these significant changes in fuel and purchased power expense, it is reasonable and necessary to increase the Company's base fuel and purchased power rate to recognize these changes in cost, which will allow APS to provide reliable service to its customers throughout the year—especially in the hot summer months when energy use is at its highest and reliability of service is the most critical. APS witness Jamie Moe will address the Company's base fuel and purchased power request.

V. AG-X

Q. PLEASE BRIEFLY DESCRIBE APS'S AG-X PROGRAM.

A. The AG-X program allows participating APS customers with an aggregated peak load of ten MW or more that are served under Rate Schedules E-34, E-35, E32-L, or E-32 TOU L to negotiate a power purchase with a third-party generation service provider (GSP). The power is delivered to APS and the Company serves the

customer. APS credits the customer for the purchase, settles any energy imbalance, and remains responsible for providing transmission and distribution grid services and generation capacity according to the customer's rate schedule. Additionally, the Company remains responsible to AG-X customers as the provider of last resort, which means the Company ensures that AG-X customers have energy at all times.

Q. HOW IS APS ADDRESSING THE AG-X REQUIREMENTS FROM DECISION NO. 78317?

A. In Decision No. 78317 (November 9, 2021), the Commission ordered APS to engage with AG-X stakeholders to analyze and identify solutions on the following items: cost shifts, resource adequacy, scheduling imbalance, transmission capacity resource constraints, another buy-through program for smaller and larger customers, carve outs for specific classes, and ensuring equitable opportunities for participation when the program is fully subscribed.

In response to this decision, APS held nine meetings with AG-X stakeholders to discuss key issues prior to the filing of this rate case. Some of the issues raised in the 2019 Rate Case have been addressed by the stakeholder efforts at the time of this filing. APS is committed to continuing these discussions and will update the Commission as additional decisions are reached.

Regarding the items identified in Decision No. 78317, I will discuss program expansion, imbalance settlements, resource adequacy requirements, and transmission delivery, while APS witness Jessica Hobbick will discuss the cost shift, updated reserve capacity charge, modifications to administrative charges, and customer participation.

Q. HOW IS APS PROPOSING TO MODIFY ITS AG-X PROGRAM?

A. APS proposes the following changes to the AG-X program:

- Providing AG-X customers two reserve capacity rates to choose from, depending on whether they elect to provide their own resource adequacy;
- Modifying the program's administrative charge to more accurately reflect the cost to manage the AG-X program;
- Reducing the aggregated peak load requirement and modifying program eligibility to allow E-32 Medium and E-32 Small customers to participate; and
- Modifying the PSA off-system sales provisions to address the cost shift to non-AG-X customers.

I will be covering the resource adequacy proposal, while Ms. Hobbick will be covering the administrative charge, off-system sales, reserve capacity charge, and the program eligibility proposals.

Q. WHAT IS RESOURCE ADEQUACY?

A. North American Electric Reliability Corporation (NERC) defines resource adequacy as the ability of supply-side and demand-side resources to meet aggregate electrical demand. In simple terms, resource adequacy is a commitment from resources to prioritize service to a specific electrical demand and is measured by the ability to serve the load (accounting for normal levels of forced outages, derates, deliverability, etc.). Resource adequacy is a critical characteristic for reliability planning. APS considers the following characteristics to be important when deciding whether a resource or capacity purchase can be utilized for the purposes of reliability planning:

- The resource or capacity is not already being utilized for resource adequacy by any other entity, which could lead to double counting of the resource in emergency conditions;

- The resources are owned, contracted by APS, or otherwise available to be called upon for the reliability of APS's system; and
- The resource or capacity purchase includes high priority or firm transmission to ensure the generation will be delivered to serve APS customer load, including assurances of access to the APS balancing area authority.

Q. WHY ARE THESE CHARACTERISTICS IMPORTANT?

A. Only resources that meet these characteristics can be relied upon to meet APS customer needs during peak hours and are not subject to being recalled during grid reliability events. Energy resources that do not have the characteristics listed above have higher susceptibility to curtailment during reliability events; there is no guarantee those resources will be available to serve APS customers when those resources are needed most, which means they are essentially on an as-available basis. The events over the past three summers highlight the need for long-term resource planning and resource adequacy. It is critical for the Company to maintain resource adequacy to provide energy security for APS customers.

Q. DO THE SCHEDULES PROVIDED BY AG-X PROGRAM PARTICIPANTS MEET THE CHARACTERISTICS OF RESOURCE ADEQUACY?

A. Under the current program structure, AG-X participants are not required to demonstrate that filed energy schedules have reliability characteristics of industrywide resource adequacy principles and requirements that ensure they can be relied on during critical periods. The program specifies that energy schedules be provided consistent with the terms of Western System Power Pool (WSPP) Schedule C, which do not preclude the energy from being recallable or require that transmission terms be specified. For instance, portions of the energy supplied may rely on generation availability in the day-ahead or real-time market to fulfill

customer obligations under the program, but if there are no remaining resources available, then these resources risk not being awarded or are subject to curtailment.[5]

Q. WHAT ARE THE IMPACTS OF THE EXISTING AG-X STRUCTURE ON RESOURCE ADEQUACY?

A. AG-X customers can schedule energy that is sourced from resources that are designated as resource adequacy resources for California customers. While most days of the year this is not a problem, the challenge exists when regional supplies are tight and AG-X customer-designated resources are either not available or are recalled to meet the priority loads the physical resource is contracted to serve.

For example, on August 18, 2020, the results of this practice had a demonstrated impact on a portion of AG-X customer energy schedules. On that date, nearly 60% of the AG-X schedules were curtailed, requiring APS to serve AG-X customers and leaving all APS customers less resilient if an unplanned event occurred. Similar events have been observed in 2021 and 2022, with up to 74% of supplies being curtailed.

As APS explores regional resource adequacy sharing opportunities, it is critical to know the source and reliability of planned resources to participate and unlock potential customer savings and reliability benefits. The current AG-X structure is, therefore, a barrier to moving forward with certain Western regional solutions to address anticipated capacity shortfalls for APS customers. Additionally, the current AG-X program may not meet resource adequacy requirements of a regional program and require additional procurement and costs to APS customers. Most

[5] *See* WSPP Schedule C and Western Electricity Coordinating Council (WECC) definition for firm sales.

existing resource adequacy programs require the level of sufficiency and granularity proposed in my testimony.

Q. HOW DOES APS'S PROPOSAL ADDRESS RESOURCE ADEQUACY?

A. APS is proposing AG-X program changes to create transparency for the reliability characteristics of the energy designated for resource adequacy. These changes will allow for more precision in the planning process. APS believes the lack of transparency has led to historic misalignment between AG-X program participants and the Company's reliability obligation, and that these two customer options set a framework for appropriate resolution of this misalignment.

Overall, this proposal is meant to appropriately value the full cost of resource adequacy and provide an option to the AG-X customers of whether to procure the necessary resource priority and provide appropriate details sufficient for APS to plan accordingly, or to have APS provide the service. In either case, the proposal is meant to protect APS customers from cost shifts associated with a lack of resource adequacy from AG-X customers. As detailed earlier in my testimony, the challenges associated with capacity shortfalls in the Western region are more pronounced today than in any other time in recent history. As such, new solutions are needed to ensure APS customers are protected.

Q. PLEASE DESCRIBE THE CHANGES BEING MADE TO ADDRESS RESOURCE ADEQUACY WITHIN THE AG-X PROGRAM.

A. APS is proposing to include a resource adequacy requirement for all AG-X customers.

To allow optionality for AG-X customers, APS is proposing two rates that would allow AG-X customers to either provide their own resource adequacy and avoid paying the reserve capacity charge or elect to have APS supply resource adequacy

and pay the reserve capacity charge as discussed. Ms. Hobbick's testimony provides further detail about this charge. The intent of having two rates is to allow a choice to those who elect to supply their own resource adequacy and pay a lower rate than those who choose to rely on APS providing resource adequacy.

Q. HOW WILL APS DETERMINE WHETHER AN AG-X CUSTOMER IS PROVIDING THEIR OWN RESOURCE ADEQUACY?

A. APS proposes to adopt a set of resource adequacy guidelines consistent with what APS uses for its own resource adequacy procurements. The proposed guidelines require:

- The AG-X customer shall provide information on the specific source at the time of the resource adequacy showings. Source specification may include a specific generating unit, specified aggregation or system of resources, or a specified balancing authority area, but should be clearly identified in advance.
- The AG-X customer shall provide an attestation and documentation specifying the resource adequacy import is a specific resource, aggregation of physically linked resources, or capacity in excess of the host balancing authority area or supplier's existing commitments, and that it is dedicated to serving APS customer load.
- The energy being purchased for resource adequacy can be delivered to APS at an agreed upon location via firm transmission.

If an alternate definition of resource adequacy is adopted by APS based on participation with a regional resource adequacy sharing organization, this definition may have to be supplemented.

Q. IS APS PROPOSING TO CONTINUE THE 15% RESERVE MARGIN FOR CUSTOMERS WHO PROVIDE THEIR OWN RESOURCE ADEQUACY?

A. APS is responsible for responding to unplanned events, such as generation outages, inclement weather, or transmission-related curtailments that could affect service reliability. Therefore, APS must maintain a reserve margin of adequate resources above 100% of its expected needs to maintain reliability. APS plans for a 15% reserve margin, which helps ensure customers do not experience a capacity-related outage. Collectively, this results in the capacity needs for 115% of an AG-X customer to ensure resource adequacy. Under APS's proposal, AG-X customers who elect to provide their own resource adequacy will be required to provide energy-backed resources for 115% of their energy usage to account for the generation needed to serve their load as well as the 15% reserve margin, which is intended to manage through unplanned events. APS's proposed approach allows for reasonable accommodations for generation outages on the APS system as well as supporting reasonable impacts that may occur to AG-X energy schedules.

Q. WHEN IS APS PROPOSING THAT RESOURCE ADEQUACY BECOME EFFECTIVE?

A. APS proposes an effective date of one year after the effective date of new rates in this case, which is intended to provide AG-X customers with a transition time period. During that period, APS will work with AG-X customers to review options and develop transition plans and operational details.

Q. IS APS REQUESTING TO CHANGE THE NOTIFICATION TIME REQUIRED TO LEAVE THE PROGRAM?

A. Yes. Under this proposal, AG-X customers that elect to have APS provide resource adequacy will provide APS with one year's notice to leave the AG-X program. AG-X customers that are providing their own resource adequacy will provide APS with three year's notice to allow APS sufficient time to plan and implement

required system changes. These notification period requirements are needed to ensure APS is able to adequately procure resources to replace the AG-X customers' historic resources, and to do so in an affordable manner. A shorter notification period would increase the risk for APS to obtain resources necessary to serve the returning customer, and the shorter period could cause higher costs for the remaining resources available in this constrained market.

Q. IS APS RECOMMENDING THAT THE AG-X PROGRAM BE EXPANDED?

A. No. APS has a number of concerns with program expansion, including resource adequacy, cost shifts to non-AG-X customers, and transmission access.

If the Commission adopts APS's proposed resource adequacy requirements, APS will monitor the effect of this change to ensure that the resource adequacy proposal is effective in mitigating the potential harm to non-AG-X customers before exploring program expansion.

Q. DID APS ADDRESS CONCERNS WITH IMBALANCE SETTLEMENTS FOR THE AG-X PROGRAM?

A. Yes. In collaboration with stakeholders, APS has implemented changes to the intraday scheduling protocols in order to reduce imbalance settlements and increase AG-X customer operational flexibility.

Q. HOW DOES APS PROPOSE TO ADDRESS TRANSMISSION CONSTRAINTS ASSOCIATED WITH THE PROGRAM?

A. AG-X customers currently use Palo Verde as a resource delivery point. However, growth in AG-X deliveries at Palo Verde displaces APS's ability to most affordably site resources to meet non-AG-X customer needs. This impacts all APS customers because, without the ability to affordably site resources at Palo Verde, APS must develop assets at other locations to serve non-AG-X customers, such as

retail customers, requiring costly additional transmission expense to reach the market. However, other transmission delivery points are available, and APS will work with AG-X customers that would like to deliver at locations other than Palo Verde, based on availability.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Long-Term Purchased Power Agreements in effect during the Test Year

Agreement	Resource Type	In-Service Date/ Initial Delivery Date
Ajo Improvement Co	System Energy	Dec 2011
RE Ajo I	Photovoltaic Solar	Sept 2011
Aragonne	Wind	Dec 2006
Arlington Tolling	Natural Gas	Jun 2020
Solana	Concentrated Solar Power with Storage	Oct 2013
CE Turbo	Geothermal	Jan 2006
Desert Sky	Photovoltaic Solar	Nov 2013
Electrical District No. 3	System Energy	May 2002
RE Gillespie	Photovoltaic Solar	Dec 2013
Griffith Tolling	Natural Gas	Jun 2020
Harquahala Tolling	Natural Gas	Jun 2021
High Lonesome	Wind	Jul 2009
Perrin Ranch	Wind	Jun 2012
SRP Eastern	System Energy	Jun 2020
Snowflake/Novo	Biomass	Jun 2008
South Point Tolling	Natural Gas	Jun 2021
SunE AZ1 (Prescott)	Photovoltaic Solar	Nov 2011
SunE AZ2 (Saddle Mtn)	Photovoltaic Solar	Dec 2012
WM Renewable	Biogas	Aug 2012

ARIZONA PUBLIC SERVICE COMPANY
Long-Term Purchased Power Agreements executed during the Test Year

Agreement	Resource Type	Expected In-Service Date
AES Westwing II	Energy Storage	June 2023
AES Agua Fria	Energy Storage	June 2024
Arlington Tolling – Extension	Natural Gas	June 2026
Mesquite Solar 5	Photovoltaic Solar with Energy Storage	June 2023
Sun Streams 3	Photovoltaic Solar with Energy Storage	June 2024
Chevelon Butte	Wind	June 2023

DIRECT TESTIMONY OF JESSICA E. HOBBICK
On Behalf of Arizona Public Service Company
Docket No. E-01345A-22-0144

October 28, 2022

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DIRECT TESTIMONY OF JESSICA E. HOBBICK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jessica E. Hobbick. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Regulation and Pricing for Arizona Public Service Company (APS or Company).

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have been employed by APS for 23 years, 17 of which I worked in Customer Service. During my time in Customer Service, I held a variety of positions, including Credit and Collections Leader and Billing Manager. I joined Regulatory Affairs in December 2016 and managed the Rate Design and Revenue Requirement teams. In 2021, I became the Director of Rates and Rate Strategy with oversight of Load Research, Revenue Requirement, Rate Design, and Rate Administration teams. I have a Bachelor of Science degree in Business Management from Grand Canyon University.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. Yes. I testified on rate design issues in APS's 2019 Rate Case. I also have participated in various Arizona Corporation Commission (ACC or Commission) workshops and Open Meetings.

II. SUMMARY OF DIRECT TESTIMONY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. In my Direct Testimony, I discuss a number of rate related topics that support APS's requested revenue increase and rate design in this case. I discuss the impact of the requested revenue increase by customer class. I also address the Company's

proposed modifications to its adjustment mechanisms and proposed changes to APS's residential and general service rate schedules. I further discuss the impact of the Company's proposals regarding its limited-income and AG-X programs. Finally, I am sponsoring Schedules H-1 through H-5, as well as the Company's rate schedules, service schedules, proof of revenue, and the residential bill impact analysis attached as JEH-01DR.

III. ALLOCATION OF COMPANY'S REQUEST TO CUSTOMER CLASSES

Q. WHAT IS THE TOTAL CUSTOMER BILL IMPACT OF THE COMPANY'S REQUESTED RATE INCREASE?

A. APS is requesting an overall net customer rate increase of $459.9 million which represents a 13.6% increase to Test Year base revenues as set forth in Figure 1.

Figure 1. Total Net Bill Impact[1]

Net Impact = Net Base Rate Increase + Net Adjustor Changes	**Dollars**	**Bill Impact**
Base Rate Increase		
Total Revenue Deficiency	$772.27M	22.87%
Adjustor Transfers	($107.83M)	(3.19%)
Base Rate Increase Net of Adjustors	$664.44M	19.68%
Day-One[2] Power Supply Adjustment (PSA) Revenue Reduction	($220.59M)	(6.53%)
Day-One Renewable Energy Adjustment Charge (REAC) CCT Revenue Increase	$16.09M	0.48%
Day-One Net Rate Impact	**$459.94M**	**13.62%**

[1] Numbers in this figure have been rounded for ease of presentation.

[2] Day One changes refer to changes in adjustor rates that will occur the same day that new base rates are implemented in this rate case.

Q. HOW IS APS PROPOSING TO ALLOCATE THIS INCREASE TO THE VARIOUS CUSTOMER CLASSES?

A. APS is proposing to allocate the rate increase to achieve similar impacts across customer classes. Attachment JEH-01DR demonstrates that nearly all residential customers will experience bill increases ranging from 10% to 17% based on their usage for the 12-month period ending June 30, 2022 (Test Year). Nearly 90% of residential customers are expected to experience an increase from 11% to 16%. Impacts to each major customer rate class are provided in Figure 2 below.

Figure 2. Percentage of Adjusted Test Year Revenue

Class	Requested Increase to Retail Revenue	Transfer from Adjustor Rates to Base Rates	Requested Increase to Base Rates	Day 1 PSA/REAC Changes	Day 1 Impact
Residential	22.79%	-3.7%	19.1%	-5.5%	13.6%
General Service					
Extra-Small, Small	23.75%	-3.0%	20.8%	-4.9%	15.9%
Medium	23.58%	-3.2%	20.4%	-7.0%	13.4%
Large	22.30%	-1.7%	20.6%	-7.6%	13.0%
Extra-Large	20.88%	-1.6%	19.3%	-10.1%	9.2%
Schools	24.17%	-5.2%	18.9%	-5.7%	13.3%
House of Worship	23.75%	-5.3%	18.5%	-4.8%	13.7%
Irrigation/Municipal	27.59%	-6.0%	21.6%	-7.9%	13.6%
Outdoor-Lighting	17.67%	-0.8%	16.9%	-3.3%	13.6%
Total Retail	**22.87%**		19.7%		13.6%

Additional detail for each specific retail rate is provided in Standard Filing Requirement (SFR) Schedule H-2.

IV. MODIFICATIONS TO APS ADJUSTMENT MECHANISMS

Q. WHAT RATE ADJUSTORS DOES APS CURRENTLY HAVE AND WHAT COSTS DO THEY RECOVER?

A. APS has seven Commission-approved rate adjustment mechanisms. However, the TEAM adjustor is currently inactive and set to zero, and therefore does not affect customer bills. Figure 3 summarizes the current Commission-approved APS adjustment mechanisms:

Figure 3. APS's Current Adjustment Mechanisms

EIS	The Environmental Improvement Surcharge (EIS) provides for the recovery of the capital carrying costs associated with qualified environmental improvement investments made by APS and not already recovered in base rates. These are projects at APS' generation facilities designed to comply with environmental standards mandated by federal, state, tribal, or local laws and regulations.
LFCR	The Lost Fixed Cost Recovery (LFCR) adjustor recovers the approved fixed cost of providing service to customers (power poles, wires, and other delivery infrastructure) that is not recovered between rate cases due to mandated energy efficiency and distributed generation programs.
TCA	The Transmission Cost Adjustment (TCA) provides a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission (FERC) and at the same time as new transmission rates become effective for APS wholesale customers.
DSMAC	The Demand Side Management Adjustment Charge (DSMAC) recovers costs for customer-focused energy efficiency and demand response programs that allow customers to reduce energy use and lower bills. Programs are approved by the Commission and comply with Arizona's Electric Energy Efficiency Standard.
REAC	The Renewable Energy Adjustment Charge (REAC) recovers the cost of Commission-approved renewable resources and customer programs to comply with Arizona's Renewable Energy Standard.
PSA	The Power Supply Adjustment (PSA) allows the Company to pass through to customers fluctuations in fuel, purchased power, storage product costs, off-system sales, and chemical costs.
TEAM	The Tax Expense Adjustment Mechanism (TEAM) allows the Company to pass through to customers income tax effects resulting from federal or state income tax legislation.

Q. WHY IS APS PROPOSING CHANGES TO ITS ADJUSTMENT MECHANISMS?

A. In Decision No. 78317 (November 9, 2021), the Commission ordered that APS submit a proposal for the modification, elimination, and/or consolidation of the

Company's adjustment mechanisms. The Company has evaluated its adjustment mechanisms and proposes several modifications.

Q. WHAT MODIFICATIONS DOES APS PROPOSE?

A. APS proposes to eliminate the LFCR and consolidate future lost fixed cost revenues with the DSMAC, eliminate the EIS, and revise the REAC as described below. APS also proposes to simplify the timing of adjustor rate resets to three times annually. Specifically, the Company's proposal is as follows:

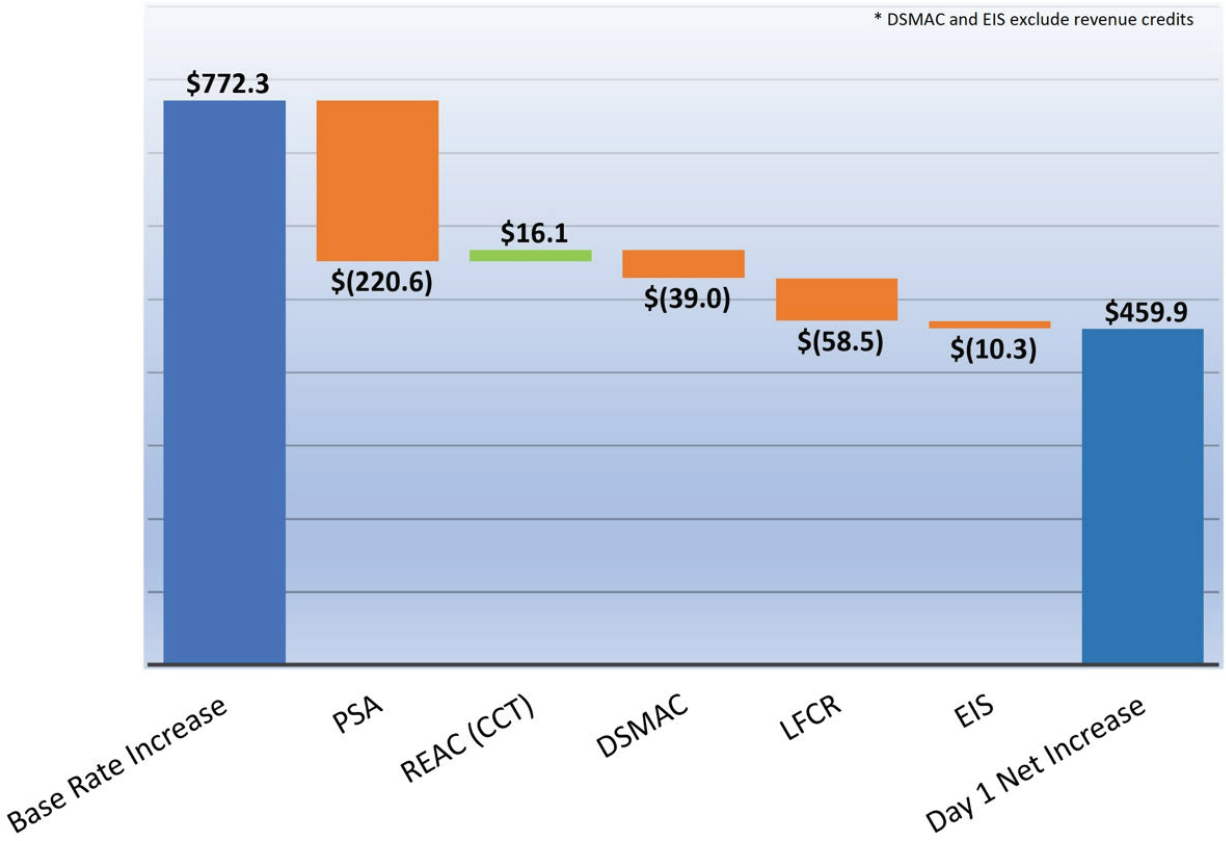
- Eliminate the LFCR adjustor by transferring $58.5 million Test Year lost fixed cost revenues into base rates and recovering future lost fixed cost revenues in the DSMAC as shown in SFR Schedule C-2, column 14.
- Eliminate the EIS and transfer $10.3 million into base rates as shown in SFR Schedule C-2, column 15.
- Transfer the Test Year amount of $39.4 million collected in the DSMAC into base rates, which currently recovers $20 million of Demand Side Management (DSM) expenses, as shown in SFR Schedule C-2, column 16, and refine the existing performance incentive (PI) as discussed further below. Total base rate collections for DSM will be $59.4 million going forward.
- Revise the REAC:

  (i) To clarify the Plan of Administration (POA) to allow recovery of carrying costs associated with renewable energy generation and energy storage investments; and

  (ii) To recover Coal Community Transition (CCT) obligations.
- Retain the PSA and reset the base fuel and chemical rate with a corresponding reduction to the adjustor.
- Retain the TCA adjustor as shown in SFR Schedule C-2, column 13.
- Leave the TEAM adjustor rate set at zero.

Below is a chart that shows the details of the base rate and adjustor changes proposed (*see* Figure 4).

Figure 4. APS Adjustor Proposal Impacts



Q. HOW WILL MOVING REVENUES COLLECTED FROM ADJUSTORS INTO BASE RATES IMPACT CUSTOMER BILLS?

A. The proposed adjustor changes are reflected in the net bill impacts provided in Figure 1 and Figure 2. Each adjustor rate will be revised to reflect the amounts that are transferred to base rates and other approved changes, on the same day as new base rates are implemented. APS's proposal is designed to minimize impacts to customer bills resulting from moving revenues from the adjustment mechanisms to base rates. Attachment JEH-01DR illustrates the bin analysis, or percentage of impact residential customers would likely experience when proposed rates are applied to Test Year usage. Because the residential TOU rates in place during the

Test Year have on-peak hours of 3:00 p.m. to 8:00 p.m., the billing determinants used in this analysis were converted to 4:00 p.m. to 7:00 p.m. to reflect the hours that were changed with Decision No. 78317. When proposed rates are applied to the billing determinants, the changes to base rates and adjustors would result in 90% of customers experiencing a bill impact between 11% and 16%. The main factors that impact the dispersion are the addition of two new holidays and adjustor changes. Converting two extra days to off-peak prices shifts usage from higher priced on-peak hours to lower priced off-peak hours. For residential demand customers, this may also lead to a lower monthly demand if their maximum demand occurred on those days. For the adjustors, each affected adjustor rate was recalculated to reflect the decrease expected to occur when balances are transferred to base rates and when corresponding reductions to the adjustors are implemented. This causes dispersion in bill impacts because the amount reduced will vary based on the customers' rate plan and the adjustor rate structure since some adjustors are assessed on energy and others on demand. Since each adjustor has its own POA which outlines the process for changing rates each year, this analysis is intended to specifically address impacts related only to this proposal, not other changes in the adjustors that may occur before new rates would go into effect.

Q. PLEASE DESCRIBE THE ELIMINATION OF THE LFCR ADJUSTOR IN MORE DETAIL.

A. APS proposes to transfer the Test Year lost fixed cost revenue amount of $58.5 million into base rates and move additional ongoing lost fixed cost revenues and balancing account adjustments occurring after the Test Year into the DSMAC. The Test Year lost fixed cost revenues were calculated using Schedule 3 and Schedule 4 from the LFCR POA, which is the same approach used to derive the lost fixed cost revenue in the annual filing. These schedules are included with my testimony as Attachment JEH-02DR to support the $58.5 million of lost fixed cost revenues

eligible for recovery under the LFCR POA for the entire Test Year. A pro forma adjustment is shown on SFR Schedule C-2, column 14, to achieve the $58.5 million transfer into base rates, which is offset by a corresponding reduction to the adjustor of $58.5 million to achieve a neutral impact to customers.

Q. HOW WILL FUTURE LOST FIXED COSTS BE RECOVERED THROUGH THE DSM ADJUSTMENT MECHANISM?

A. Future lost fixed costs will continue to be calculated under the POA, outlined in Schedules 2 through 10, and subject to the annual earnings test. The revenue requirement will then be added to the DSMAC budget, and the rate calculated consistent with the terms in the DSMAC rate schedule filed annually for Commission approval. Proposed changes to the DSMAC POA are included in Attachment JEH-03DR, Redline DSMAC POA, and Attachment JEH-04DR, Clean DSMAC POA.

Q. WAS APS REQUIRED TO PROPOSE ADDITIONAL MODIFICATIONS TO THE DSM ADJUSTMENT MECHANISM?

A. Yes. Decision No. 78499 (March 2, 2022) requires APS to include in this rate case one or more proposals to rate base Demand-Side Resource investments for potential consideration by the Commission.

Q. HOW WOULD RATE BASE TREATMENT FOR DSM EXPENSES IMPACT CUSTOMERS?

A. Generally, including DSM program expenses in rate base would entail establishing a regulatory asset based on fixed annual program expenses over an established number of years in between rate cases and amortizing those costs to achieve an annual revenue requirement impact. This asset would then be eligible to earn at the Company's authorized rate of return and any fluctuations in program spend, both above and below the amount collected in rates as established in a rate case, would be deferred into the regulatory asset and recovered in a future rate case proceeding.

Q. DOES APS PROPOSE RATE BASE TREATMENT OF DSM EXPENSES?

A. No. APS believes that an enhancement to the existing DSM PI strikes the balance between rate gradualism and concurrent cost recovery while continuing to encourage the development of programs that provide peak load reduction and other beneficial grid services for customers. Continuing to propose an annual budget for review and approval allows for the development or expansion of programs as the need arises, as opposed to having a predetermined budget built into rates that would require a general rate case proceeding to recover costs associated with any modifications to these programs.

Q. PLEASE DESCRIBE THE EXISTING DSM PERFORMANCE INCENTIVE.

A. Currently the DSM PI allows for recovery of up to 8% of net benefits generated from qualifying energy efficiency programs. The PI, most recently approved in Decision No. 74406 (March 19, 2014), is calculated using the lesser of a share of the calculated net benefits achieved by energy efficiency programs using the Commission-approved method of calculating cost effectiveness, or the annual kWh savings achieved from the DSM portfolio multiplied by $0.0125 per kWh. Figure 5 shows the existing DSM PI methodology. In the 2022 APS DSM Plan, this resulted in a proposed $4 million PI based on a 7% share of the estimated $56.5 million in net benefits.

Figure 5. Existing DSM PI Methodology

Achievement Relative to Annual Goal Approved in APS's Energy Efficiency Implementation Plan	Performance Incentive as % of Energy Efficiency Net Benefits	Performance Incentive Cap*
< 85%	0%	Performance Incentive Will Not Exceed $0.0125/kWh Saved
85% to 95%	6%	
96% to 105%	7%	
> 105%	8%	

*The PI cap applies to the annualized incremental first year energy savings generated.

Q. HOW DOES APS PROPOSE TO REFINE THE DSM PERFORMANCE INCENTIVE?

A. APS proposes to modify the PI to include demand response program net benefits in the calculation of the PI and modify the current cap structure to recognize that addition by including the savings from demand response programs, converted from MWs to equivalent MWhs, in the calculation of the cap. Since the incentive benefit is currently booked as revenues, it would produce benefits to the Company very similar to the rate base proposal at a lower cost to customers. This proposal recognizes the evolution of demand response which now provides more than 150 MWs of peak load reduction and is a more prominent share of the overall DSM portfolio than it was when this incentive structure was originally adopted. Assuming these changes were adopted and using the 2022 filing to reflect those impacts, the PI would have increased by approximately $763,000 resulting in roughly $4.7 million in benefits as shown in Figure 6 below. Updating the PI to include benefits from demand response programs will better align the structure of the incentive, which already includes energy efficiency net benefits, with the delivery of efficient and cost-effective demand response programs that provide

customer benefits and support Commission policy objectives to reduce peak demand.

Figure 6. Estimated 2022 DSM Performance Incentive

Estimated 2022 DSM Performance Incentive (Based on 7% of Net Benefits for EE + DR Programs)	
Estimated Net Benefits from EE Programs	$56,537,910
Estimated Net Benefits from DR Programs	$10,904,276
Total Net Benefits	$67,442,186
% of Net Benefits (based on achieving between 96-105% of the annual DSM savings goal)	7%
Performance Incentive from EE Programs	$3,957,654
Performance Incentive from DR Programs	$763,299
Performance Incentive from EE & DR Programs	$4,720,953

Q. PLEASE DISCUSS APS'S PROPOSED CHANGES TO THE PSA.

A. APS seeks a reduction in the PSA commensurate with the base fuel increase described in the testimony of APS witness Justin Joiner. The base fuel increase includes $1.18 million in the Base Fuel and Purchased Power Costs pro forma, $212.28 million in the Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accrual pro forma, and $7.14 million in the Chemical O&M pro forma. The sum of these three amounts is equal to $220.59 million which reflects both the increase to base rates and the decrease to the PSA on the date new rates become effective to result in a neutral customer impact. This impact does not include PSA rate changes that are proposed to take effect in February of 2023 and 2024 to continue recovering historical fuel variances.

Q. DOES THE PROPOSED FUEL COST REFLECT THE ELIMINATION OF $15 MILLION IN COST RECOVERY FOR THE AG-X PROGRAM?

A. Yes. The PSA rate currently recovers $15 million for the mitigation of certain cost recovery deficiencies from the AG-X program. However, APS proposes to eliminate the recovery of this amount in this proceeding and thereby reduce overall fuel expenses by $15 million. The impacts to base fuel and the PSA reflect this proposed change.

Q. PLEASE FURTHER DESCRIBE THE MODIFICATION OF THE REAC.

A. As APS increases its investments into clean energy and energy storage resources, customers stand to gain significant benefits. APS witness Theodore N. Geisler and Mr. Joiner discuss further the important benefits to customers from making these investments. Revising the scope of the allowable costs in the REAC POA to permit recovery of these clean energy investments is critical to cost-effectively achieving these outcomes for customers. APS proposes an annual earnings test to determine the maximum amount that can be recovered in the REAC each year. The earnings test would compare the previous year's unadjusted rate of return with the return on equity authorized in the Company's most recent rate case (with an updated capital structure and cost of debt adjusted to account for authorized revenues associated with the fair value increment). APS proposes that this same earnings test apply to the future recovery of lost fixed costs to be recovered through the DSMAC adjustor, rather than two separate tests. Proposed changes to the REAC POA are included in Attachment JEH-05DR, Redline REAC POA, and Attachment JEH-06DR, Clean REAC POA.

Q. WHICH COSTS WOULD BE RECOVERED THROUGH THE REAC?

A. The capital carrying costs related to new renewable and energy storage resources owned by APS include: (1) the return on net plant, which is based on the weighted average cost of capital approved in APS's most recent rate case; (2) depreciation

expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits, where appropriate; and (6) associated operations and maintenance (O&M) expenses. The Company also proposes to recover $106.5 million for CCT obligations through this adjustment mechanism, which is discussed in the testimony of APS witness Jacob Tetlow. Figure 7 summarizes the annual collection of CCT funds through the REAC.

Figure 7. Annual Impacts of APS's CCT Proposal

Description	Amount	Term	Years 1-3	Years 4-8	Year 9
$5 million Navajo Nation electrification less $1.25 million approved in Decision No. 78317	$3,750,000	3 years	$1,250,000	$0	$0
$10.9 million Navajo Community support less $500k approved in Decision No. 78317	$10,400,000	3 years	$3,466,667	$0	$0
$3.35 million in Hopi Tribe CCT support less $1 million approved in Decision No. 78317	$2,350,000	3 years	$783,333	$0	$0
$100 million in Navajo Nation CCT support less $10 million approved in Decision No. 78317	$90,000,000	8.5 years	$10,588,235	$10,588,235	$5,294,118
		Total	$16,088,235	$10,588,235	$5,294,118

Q. WHAT IS THE COMPANY'S PROPOSED MODIFICATION OF ADJUSTOR RATE RESETS?

A. Under the Company's proposal, the Plans of Administration for the DSMAC and REAC adjustors would be modified to better align adjustor resets as shown in Figure 8 below. Thus, customers would experience only three adjustor rate adjustments each year.

Figure 8. Proposed Adjustment Mechanism Review Schedule

Mechanism	Filing Date	Adjustor Rate Effective Date
PSA	November 30th	February
TCA	May 15th	June
DSMAC	November 30th	October
REAC	November 30th	October

Q. DID APS CONDUCT STAKEHOLDER MEETINGS TO DEVELOP THIS ADJUSTMENT MECHANISM PROPOSAL?

A. Yes. In April and May 2022, APS held stakeholder meetings to elicit feedback from interested parties including Residential Utility Consumer Office (RUCO), Staff, Western Resource Advocates (WRA), Sierra Club, and others.

V. RATE DESIGN

Q. PLEASE DESCRIBE APS'S PROPOSED CHANGES TO RESIDENTIAL AND GENERAL SERVICE RATE SCHEDULES.

A. APS proposes to continue offering three residential rate options: one basic rate, one time-of-use (TOU) rate, and one TOU with demand rate with two additional off-peak holidays. APS has designed two seasonal versions of the Residential Fixed Energy Charge plan (R-1) as required by Decision No. 78317. However, the Company believes that the Commission should retain the existing rate plan structure.

Q. WHAT ADDITIONAL OFF-PEAK HOLIDAYS IS APS PROPOSING?

A. APS proposes two additional off-peak holidays, Juneteenth and Indigenous Peoples' Day/Columbus Day. On these days, residential customers on TOU rate

plans would experience off-peak prices during all hours of the day. If the holiday falls on a weekend, the nearest weekday will be considered the off-peak day.

Q. WHY IS APS PROVIDING MULTIPLE VERSIONS OF THE FIXED ENERGY CHARGE (R-1) RESIDENTIAL RATE?

A. Decision No. 78317 required that APS design basic rates with and without seasonality, and more specifically that two additional versions of this rate be proposed in APS's next rate case with seasonal charges: one that is revenue neutral with the current rates and one that recovers a greater portion of the cost of service.

Q. WHAT CUSTOMER IMPACTS WOULD RESULT FROM INCLUDING SEASONAL RATES IN R-1 RATE PLANS?

A. There are two scenarios that reflect the impacts of adding seasonality to the R-1 rate plans. One is revenue neutral with proposed rates and isolates impacts of incorporating seasonality, and the second recovers a greater portion of the cost of service. In the revenue neutral scenario, summer energy charges increased by 6% and winter energy charges reduced by 8% to achieve a difference of approximately 15%. This results in bill impacts ranging across a wider span, from an 8% to 20% bill increase for most customers. For the second scenario, the summer and winter energy charges in scenario two were increased by 3% to maintain the same 15% seasonal difference and recover a larger portion of the cost to serve, which is more consistent with other residential rates. This causes a similar dispersion, with bill impacts ranging from a 12% to 23% bill increase for most customers.

Figure 9. Summary of Seasonal Rates Analysis

	Seasonal: Revenue Neutral			Seasonal: Higher Cost of Service		
	R-1 S	R-1 M	R-1 L	R-1 S	R-1 M	R-1 L
Daily Basic Service Charge	$0.393	$0.500	$0.500	$0.393	$0.500	$0.500
Summer Energy ($/kWh)	$0.14639	$0.15821	$0.17415	$0.15110	$0.16351	$0.18025
Winter Energy ($/kWh)	$0.12729	$0.13749	$0.15136	$0.13105	$0.14176	$0.15632

Q. IS THE MODIFICATION OF R-1 IN THE BEST INTEREST OF CUSTOMERS?

A. Not at this time. Although seasonal rates are designed to recover more revenue in the summer months when costs to serve are higher, further evaluation revealed adverse impacts to customers. Increasing summer rates would create additional hardship for vulnerable customers during months in which bills are the highest. For these reasons, APS does not recommend changing the R-1 rate structure at this time. In addition, if the Commission were to adopt seasonal rates as previously discussed, rates in the proof of revenue would need to be recomputed for R-1 to reflect the revenue neutral option and other residential rates would also need to be redesigned to address the additional revenue recovered in the non-revenue neutral option.

VI. LIMITED-INCOME PROGRAM RECOMMENDATIONS

Q. PLEASE DESCRIBE APS'S LIMITED-INCOME BILL DISCOUNT PROGRAMS.

A. APS provides two bill-discount programs for customers with limited-income. The E-3 rate rider provides a 25% bill discount for customers that are within 200% of the Federal Poverty Level (FPL). The E-4 rate rider provides a 35% bill discount for customers within 200% of the FPL who also have certain qualifying medical equipment. In addition to these discount programs, APS funds Crisis Bill Assistance, which provides an additional $2.5 million annually for bill assistance administered by third parties.

Q. WHAT IS THE CURRENT ENROLLMENT LEVEL AND FUNDING FOR THESE PROGRAMS?

A. The E-3 and E-4 programs had a combined participation of 70,592 customers at the end of the Test Year. Customers enrolled in these programs received

$33,824,005 in discounts during the Test Year, which is more than double the program amount provided in discounts by any other Arizona utility.

Q. HOW HAS PARTICIPATION IN THESE PROGRAMS CHANGED?

A. During the current Test Year, participation increased 29% from 54,706 in APS's last test year ending June 30, 2019.

Q. IS APS PROPOSING CHANGES TO THE E-3 LIMITED-INCOME DISCOUNT PROGRAM?

A. Yes. Consistent with Decision No. 78317, APS engaged stakeholders to develop an alternative discount program centered around energy burden.

Q. PLEASE DESCRIBE APS'S PROPOSED ALTERNATIVE LIMITED-INCOME DISCOUNT PROGRAM.

A. The proposed program is discussed by APS witness Monica Whiting and includes two tiers based on the household income of the applicant. Overall participation in the program would continue to be based on income not exceeding 200% of the FPL. Customers who earn between 0-75% of the FPL would receive a larger discount than those who earned greater than 75% up to 200% of the FPL. The discount percentages were designed to achieve an average energy burden of approximately 6% or less. This means that when the annual energy costs are divided by the annual income, the level of energy cost reduction needed to achieve approximately 5-6% of the annual income results in the discount percentage. To simplify the administration of the program and streamline system implementation, while also providing customer certainty on the discount applied to the bill, two tiers were designed based on the average annual energy costs for existing E-3 participants applied to actual levels of reported income for a sample of approximately 31,000 E-3 customers. The resulting two discount tiers are shown in Figure 10. Proposed changes to the E-3 Rate Rider are included in Attachment

JEH-07DR, Redline E-3 Rate Rider, and Attachment JEH-08DR, Clean E-3 Rate Rider.

Figure 10. Limited-Income Proposal Discount Tiers

FPL Level	Discount %	Energy Burden Target	Monthly Discount Cap	Estimated Customer Count	Total Discount & Admin
0-75%	60%	6.24%	$165	18,707	$18,350,766
>75%-200%	25%	5.2%	$95	51,885	$22,971,839
					$ 41,322,605

Q. WHY ARE THE CAPS IMPOSED ON MONTHLY DISCOUNT AMOUNTS?

A. Caps are imposed in recognition that the discount costs are borne by all customers. The caps were designed to accommodate average bills up to $275 and $380 per month dependent upon the tier, which allows approximately 92% of the bills included in the 25% discount tier to remain unaffected by the cap during peak July bills. While 85% of customers in the 60% discount tier remain unaffected by the cap, less than 1% of those that are affected would experience a lower discount in July than they do under the current 25% discount structure. These caps will also be supported with customer education on energy efficiency programs, budget billing, and rate comparisons to help customers manage their usage to maximize bill savings.

Q. WILL CUSTOMERS WITH QUALIFYING MEDICAL EQUIPMENT GET A LARGER DISCOUNT?

A. E-4 customers will receive an additional 10% on top of the 25% tier of the E-3 discount, or 35% for participants meeting the >75% - 200% of FPL tier, which is the same discount they receive under the current program. E-4 participants in the 0-75% tier will receive the 60% discount, which is 25% more than they receive under the current E-3 construct. Proposed changes to the E-4 Rate Rider are

included in Attachment JEH-09DR, Redline E-4 Rate Rider, and Attachment JEH-10DR, Clean E-4 Rate Rider.

Q. HOW MUCH MORE WILL THIS PROGRAM COST TO SUPPORT?

A. If the proposed discount program discussed above is approved, $41,322,605 will be required to support the discount levels and administrative costs to administer the program. The current Test Year experienced $34,465,169 in discounts and administrative costs. The difference between these two amounts represents the additional funding that would be needed resulting in a pre-tax decrease to operating income of $6,857,437 as shown in SFR Schedule C-2, column 22.

Q. PLEASE DESCRIBE THE LIMITED-INCOME DISCOUNT DEFERRAL PRO FORMA ADJUSTMENT.

A. In Decision No. 78317, the Commission approved the deferral of discounts above or below test year levels for future recovery. The amount approved for recovery in rates was $19,397,104. To determine the excess amount, each month of the Test Year following the December 1, 2021 approval of this deferral was compared to the corresponding month in the prior July 1, 2018 through June 30, 2019 test year. The portion of the $19,397,104 annual discount amount that reflected December 1, 2018 through June 30, 2019 was $9,715,273. The amount of discounts awarded between December 1, 2021 and June 30, 2022 was $15,890,061, representing an additional $6,174,788. This balance amortized over a three-year period represents an annual pre-tax decrease to operating income of $2,058,262 as shown in Schedule C-2, column 23. APS also seeks to continue this treatment approved in Decision No. 78317.

Q. IS SPECIFIC LANGUAGE BEING REQUESTED TO ALLOW FOR THE TRACKING OF CUSTOMER DISCOUNTS AND DEFERRAL OF COSTS RELATED TO THE LIMITED-INCOME PROGRAM?

A. Yes. Generally Accepted Accounting Principles (GAAP) require that the regulatory authorization of the deferral include language that provides APS and its auditors with reasonable assurance that the Company will recover prudently incurred costs in future rates. In order for the Company to recognize an accounting deferral on its general ledger, the ordering language authorizing such a deferral must be clear and unequivocal about what is being deferred and the potential for the deferral's recovery or refund in rates in a specific future rate proceeding. Thus, APS requests the ordering language as follows:

> IT IS FURTHER ORDERED that APS is authorized to track discounts paid to customers and to defer program costs incurred above or below the level authorized in this case on the limited-income programs (E-3 and E-4) for possible later recovery or refund through rates. Nothing in this Decision shall be construed in any way to limit this Commission's authority to review the entirety of the program and to make any disallowances thereof due to imprudence, errors, or inappropriate application of the requirements of this Decision.

Q. HOW DO APS'S LIMITED-INCOME DISCOUNTS COMPARE WITH OTHER ARIZONA UTILITIES?

A. APS's current discounts are far greater than other Arizona utilities. For example, Salt River Project offers a discount of $23 per billing cycle. Tucson Electric Power Company currently has an $18 discount or a grandfathered discounted limited-income retail rate. The average bill discount during the Test Year from APS's E-3 program was $36.33 per month. This amount was calculated by taking the Test

Year discount amount of $33,824,005 and dividing it by the 931,037 annual Test Year number of customer bills receiving the discount.

VII. AG-X MODIFICATION PROPOSAL

Q. WHAT PART OF THE ALTERNATIVE GENERATION (AG-X) BUY-THROUGH PROGRAM WAS APS ORDERED TO EVALUATE?

A. The specific elements of the program that APS was ordered to address include cost shifts, resource adequacy, scheduling imbalance, transmission capacity resource constraints, another buy-through program for smaller and larger customers, the legality of carve outs for specific classes, and equitable opportunities for participation when the program is fully subscribed.

Q. PLEASE DESCRIBE THE CURRENT AG-X PROGRAM.

A. AG-X is a retail rate rider available to APS's larger general service customers with an aggregated peak load of 10 MW or more. This program allows participants to select an alternative Generation Service Provider (GSP) in lieu of purchasing generation services directly from APS. The generation charges are negotiated between the customer and the GSP, which then replace the embedded generation charges in the customer's retail rate schedule along with the PSA. Customers enrolled in the program must also pay an administrative fee of $0.00171 per kWh and a reserve capacity charge of $5.248 per kW. They are also subject to imbalance charges that apply when scheduling deviations occur. The program is limited to a total peak load of 200 MW of participation. Proposed changes to the AG-X Rate Rider are included in Attachment JEH-11DR, Redline AG-X Rate Rider, and Attachment JEH-12DR, Clean AG-X Rate Rider.

Q. HAS APS OBSERVED CHANGES TO AG-X PARTICIPATION OVER THE PAST YEAR?

A. Yes. APS has observed reduced levels of participation that result from customers voluntarily terminating enrollment in the program. Further, APS has found that

some participants who were initially interested in the program no longer wish to take part. In the past two years, three customers left the AG-X program leaving 55 MW available for customers on the waiting list. Another customer has announced that it will leave the program in 2023 opening another 20 MW. APS has contacted five customers on the waiting list representing seven opportunities to participate, with only one accepting the invitation to enroll. There are six remaining customers on the waiting list, some of whom have previously declined to take advantage of the opportunity to enroll.

Q. WHAT CHANGES DOES APS PROPOSE FOR THE AG-X PROGRAM?

A. APS is proposing several changes to address the issues discussed above, which include: 1) modifying the administrative charge to more accurately reflect the cost to manage the program; 2) creating options for reserve capacity charges based on the customer's choice of capacity supply, as described by Mr. Joiner; 3) adding language to the rate rider schedule extending the length of notification required before a customer may terminate participation in the AG-X program, as described by Mr. Joiner; and 4) expanding the eligibility guidelines to allow for smaller class participation.

Q. ARE THE CURRENT ADMINISTRATIVE CHARGES ADEQUATE TO RECOVER COSTS TO ADMINISTER AG-X?

A. Yes. APS underwent a thorough evaluation of both personnel and system support needed to administer the program throughout the Test Year to ensure the costs recovered appropriately reflected the cost to administer the program as it exists today. Based on the results of this study, APS is proposing that the current fee of $0.00171 per kWh be reduced to $0.001640.

Q. DOES APS BELIEVE ADDITIONAL CAPACITY IN THE PROGRAM IS NECESSARY?

A. No. Based on current levels of enrollment, several customers previously on the waiting list have been provided opportunities to enroll in the program. APS does not believe an expansion is warranted at this time. Instead, Mr. Joiner proposes solutions to address flaws identified within the program and recommends that any changes adopted be monitored for effectiveness before consideration is given to expanding the size of the program.

Q. IS APS PROPOSING CARVE OUTS SPECIFICALLY FOR SCHOOLS OR OTHER INDIVIDUAL CUSTOMER TYPES?

A. No. Schools are already eligible to participate in the program. As part of the stakeholder collaboration process, participants were surveyed asking whether they support portions of the program being dedicated to specific types of facilities. The consensus of respondents supported equitable participation on a nondiscriminatory basis.

Q. WHO PROVIDES THE CAPACITY FOR THE CURRENT AG-X CUSTOMERS?

A. By default, APS provides the capacity for AG-X customers, which is one of the requirements for serving as a Balancing Authority for the service area.

Q. WHO PAYS FOR THIS CAPACITY?

A. The capacity is partially paid for by AG-X customers through a reserve capacity charge under the program. The remaining costs are paid for by other customers through the PSA off system sales mitigation, which APS proposes to eliminate and which is discussed previously in conjunction with other adjustor changes.

Q. DOES THE AG-X PROGRAM RESULT IN A COST SHIFT TO OTHER NON-PARTICIPATING CUSTOMERS?

A. Yes, because AG-X customers are not currently paying 100% of generation capacity rates reflected in their retail rate schedule. Those costs are currently being recovered from other customers in rates. APS is seeking to better align rates being recovered from participants with costs.

Q. HOW WOULD THE TWO RESOURCE ADEQUACY OPTIONS PROPOSED BY APS IMPACT THE RESERVE CAPACITY CHARGE?

A. APS proposes that the current AG-X program be modified to include two options for securing resource adequacy, which is the generation capacity needed to ensure a reliable power supply to the customer. Specifically, participants may either procure resource adequacy from a third-party or APS. Under the third-party option, the customer would avoid the reserve capacity charge. For customers that purchase their resource adequacy from APS, a reserve capacity charge of 100% of the unbundled generation demand charge included in the E-34 rate schedule would apply, which would reflect the capacity APS is required to maintain.

Q. HOW DO YOUR PROPOSED MODIFICATIONS ENABLE SMALLER SIZED CUSTOMERS TO PARTICIPATE?

A. APS is proposing a modification to the application provisions in the AG-X Rate Rider Schedule that would allow E-32 medium and small classes to participate in the program and would reduce the aggregated peak load requirement from 10 MW to 5 MW.

VIII. SERVICE SCHEDULES

Q. WHICH SERVICE SCHEDULES IS APS PROPOSING TO REVISE?

A. APS is revising:

- Service Schedule 1: Terms and Conditions for Standard Offer and Direct Access Services (Attachments JEH-13DR, Redline Service Schedule 1, and JEH-14DR, Clean Service Schedule 1);
- Service Schedule 3: Conditions Governing Extensions of Electric Distribution Lines and Services (Attachments JEH-15DR, Redline Service Schedule 3, and JEH-16DR, Clean Service Schedule 3); and
- Service Schedule 9: Conditions Governing Economic Incentives for the Industrial Development Plan (Attachments JEH-17DR, Redline Service Schedule 9, and JEH-18DR, Clean Service Schedule 9).

Q. PLEASE DESCRIBE SERVICE SCHEDULE 1.

A. Service Schedule 1 provides the terms and conditions that apply to Standard Offer and Direct Access services made available by APS.

Q. HOW DOES THE COMPANY PROPOSE TO CHANGE SERVICE SCHEDULE 1?

A. APS proposes to revise Service Schedule 1 to simplify and update existing language, including revisions to Section 12 (Limitations on Liability of Company) to make the language consistent with previously approved tariffs of peer electric and to eliminate inapplicable terminology. A redlined version of this Service Schedule with updated language is included in Attachment JEH-13DR.

Q. WHY IS THE COMPANY MAKING CHANGES TO SERVICE SCHEDULE 3?

A. APS is proposing to update the Schedule of Charges within Service Schedule 3 to simplify the construction process for customers while also reflecting actual equipment costs at the end of the Test Year. Updates to the definitions for

additional clarity around service voltage levels and utilization of the schedule of charges or project specific costs is also proposed. A redlined version of this Service Schedule with updated prices and language is included in Attachment JEH-15DR.

Q. HOW DOES THIS CHANGE BENEFIT CUSTOMERS?

A. APS is proposing to modify the Service Schedule 3 Statement of Charges methodology to a price per linear foot calculation, which will reduce more than 90 existing itemized charges. This reduction will be much easier for customers to understand and will improve turnaround times.

Q. HOW WAS THE PRICE PER LINEAR FOOT DERIVED?

A. To determine the price per linear foot, models were developed using a sample of historical projects for each classification. Material costs were updated and applied to the model, and the result was then divided by the average amount of linear feet.

Q. WHAT IS SERVICE SCHEDULE 9?

A. Service Schedule 9 provides the terms and conditions under which APS may offer financial incentives to new or existing commercial or industrial customers who add significant load. A redlined version of this Service Schedule with updated prices and language is included in Attachment JEH-17DR.

Q. WHAT ARE THE COMPANY'S PROPOSED REVISIONS TO SERVICE SCHEDULE 9?

A. APS proposes two revisions to Service Schedule 9. The first is to increase the availability of the economic incentive for rural applicants by 25 MW, as the 100 MW program has been fully allocated to non-rural customers. The second revision is to modify the requirement in Section 4.3 (Effects on Competitors) by eliminating use of the North American Industry Classification System (NAICS) code to determine the nature of the business and replacing it with job growth and capital investment criteria.

IX. PRO FORMA ADJUSTMENTS TO TEST YEAR REVENUE

Q. WHICH ADJUSTMENTS TO TEST YEAR REVENUE ARE YOU SPONSORING?

A. I sponsor the following adjustments to Test Year revenue:

- Include Proposed Limited-Income Tiered Discount pro forma (SFR Schedule C-2, column 22);
- Limited-Income Discount Deferral Amortization pro forma (SFR Schedule C-2, column 23);
- Customer Bill Payment Fees Proposal pro forma (SFR Schedule C-2, column 24);
- Base Revenue Annualization pro forma (SFR Schedule C-2, column 19);
- Transfer Test Year Lost Fixed Cost Recovery (LFCR) pro forma (SFR Schedule C-2, column 14);
- Annualize Customer Levels pro forma (SFR Schedule C-2, column 10);
- Normalize Weather Conditions pro forma (SFR Schedule C-2, column 9); and
- Annualize Test Year Tax Expense Adjustor Mechanism pro forma (SFR Schedule C-2, column 18).

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR THE PROPOSED LIMITED- INCOME TIERED DISCOUNT.

A. APS is proposing an adjustment to Test Year revenue for the additional funding to support the proposed energy burden-based discount program, which represents a reduction of $6.9 million in pre-tax operating income. A more detailed discussion of these costs and the adjustment is provided in the Limited-Income Program Recommendations section of my testimony (*see* SFR Schedule C-2, page 8, column 22).

Q. PLEASE EXPLAIN THE LIMITED-INCOME DISCOUNT DEFERRAL AMORTIZATION PRO FORMA.

A. The Company is proposing an adjustment to Test Year revenue for the limited-income discount deferral amortization which represents a reduction of $2.1 million in pre-tax operating income. A more detailed discussion of these costs and the adjustment is provided in the Limited-Income Program Recommendations section of my testimony (*see* SFR Schedule C-2, page 8, column 23).

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT FOR THE REMOVAL OF CUSTOMER BILL PAYMENT FEES.

A. As described in Ms. Whiting's testimony, APS is proposing to eliminate payment fees charged by vendors and passed on to customers in order to provide a more seamless customer experience. The impact of this adjustment results in a decrease to pre-tax operating income of $10.6 million (*see* SFR Schedule C-2, page 8, column 24). This estimate is based on the Test Year level of 13.1 million payment transactions and assumes that approximately 36% of those transactions will be converted from a payment method that does not currently include a transaction fee to a method that the Company proposes be socialized.

Q. PLEASE DESCRIBE THE BASE REVENUE ANNUALIZATION PRO FORMA THAT APS IS PROPOSING.

A. This pro forma adjustment annualizes the effects of the revenue requirement approved in Decision No. 78317 that began on December 1, 2021, across all 12 months of the Test Year, resulting in a decrease to pre-tax operating income of $71.5 million (*see* SFR Schedule C-2, page 7, column 19).

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSFER THE LFCR TEST YEAR REVENUES.

A. This adjustment annualizes the Test Year level of LFCR needed to facilitate the elimination of the LFCR as described in the Modifications to APS Adjustment

Mechanisms section of my testimony, resulting in a reduction of $58.5 million of pre-tax operating income (*see* SFR Schedule C-2, page 5, column 14).

Q. PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE CUSTOMER LEVELS.

A. The pro forma to annualize customer levels adjusts Test Year revenue to reflect customer growth or decline during the same timeframe. The adjustment is derived by first determining the change in customer levels during the Test Year for each major rate class; specifically, APS subtracts the customer level in June 2022 from July 2021. The customer level for each month is then adjusted to reflect this annual change. The monthly adjustments are multiplied first by the average kWh per customer, and then the appropriate revenue per kWh to calculate the required revenue adjustment. This process is performed specifically for each rate class, the results of which are then combined to derive an overall revenue adjustment. The change in customer levels during the Test Year was mixed for the various rate classes; some increased and others declined. Overall, the changes resulted in an increase to pre-tax operating income of $15.6 million (*see* SFR Schedule C-2, page 4, column 10).

Q. WHAT IS THE ADJUSTMENT TO NORMALIZE WEATHER CONDITIONS?

A. Test Year revenue is adjusted for normal weather (over a ten-year historical period) to demonstrate that the final level of revenue approved reflects retail energy consumption associated with average or typical temperature and humidity patterns. This adjustment is derived by estimating the impact of temperature and humidity on customer monthly energy usage and then comparing the Test Year level of these weather variables to long-run average levels. The resulting impact on energy usage is multiplied by the appropriate revenue per kWh to derive an overall revenue adjustment. The estimate of weather impact on kWh usage and the

resulting revenue adjustment is performed specifically for each rate class. The results for each class are then combined to provide the overall revenue pro forma adjustment. The Test Year began with a much milder summer, fall, and winter compared to long-term trends, and despite the subsequent warmer spring, the overall net impact is that, had the Test Year weather been "normal," the kWh consumption and revenue would have been higher. As a result, the Test Year pre-tax operating income was increased by $13.5 million for the weather normalization pro forma (*see* SFR Schedule C-2, page 3, column 9).

X. STANDARD FILING REQUIREMENTS

Q. WHICH SFRS AND TARIFFS ARE YOU SUPPORTING?

A. I am sponsoring the following SFRs and tariffs:

- SFR Schedule H-1, Summary of Base Revenues by Customer Classification;
- SFR Schedule H-2, Analysis of Base Revenues by Detailed Class;
- SFR Schedule H-3, Comparison of Present and Proposed Rates;
- SFR Schedule H-4, Typical Bill Analysis at Present and Proposed Rates;
- SFR Schedule H-5, Billing Activity by Block for Each Major Rate - Consumption;
- Rate schedules;
- Service schedules;
- Proof of revenue; and
- Residential Bill Impact Analysis (Attachment JEH-01DR).

Q. PLEASE DESCRIBE THESE SFRS.

A. Here is a description of the SFRs:

- SFR Schedule H-1 determines the present and proposed Test Year revenue for major customer classifications.
- SFR Schedule H-2 presents similar information for all major rate classes.

- SFR Schedule H-3 lists all current and proposed bundled charges for each rate schedule.
- SFR Schedule H-4 is a bill comparison of present and proposed rates by various monthly usage levels for each major rate.
- SFR Schedule H-5 demonstrates the frequency distribution of customer bills by usage level for each major rate.
- Residential Bill Impact Analysis (Attachment JEH-01DR) by bin shows the number of residential customers who fit within 5% ranges of bill impacts.
- I also sponsor an index of all rate schedules and service schedules, along with all actual schedules.

Q. PLEASE DESCRIBE APS'S PROOF OF REVENUE ANALYSIS.

A. APS's proof of revenue analysis validates the billing determinants used in the Test Year. By billing out current rates against these billing determinants, APS matches the Company's current Test Year revenue.

Q. PLEASE DESCRIBE THE BILL IMPACT BY BIN ANALYSIS.

A. APS is providing a residential bill analysis to estimate the level of bill increase or decrease customers may experience upon the implementation of new rates, using Test Year usage. To prepare this analysis, each customer's Test Year billing details, including billed days, on- and off-peak kWh, and kW demand are rebilled under proposed rates and adjustors. The results are then compared to the amount customers are billed under present rates and adjustors to determine the impact percentage. This analysis is included in Attachment JEH-01DR.

XI. ELIMINATION OF DUPLICATIVE AND OUTDATED COMPLIANCE FILINGS

Q. WHAT EXISTING COMPLIANCE FILING OBLIGATIONS IS APS PROPOSING THAT THE COMMISSION WAIVE OR ELIMINATE?

A. APS is asking that the Commission waive or eliminate duplicative and outdated compliance filings and requirements. The Company does not seek to avoid any substantive requirement of a prior Commission order or regulation, but simply seeks to eliminate duplicative or outdated reporting requirements that have become obsolete and are no longer necessary. Absent relief, APS must continue to comply with these various compliance requirements and Commission Staff must continue to verify that compliance unless these requirements are formally waived or otherwise removed by Order of the Commission. Please see Attachment JEH-19DR, Proposed Compliance Elimination List, for a more detailed description and justification on the requested waivers and eliminations.

XII. CONCLUSION

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Residential Bill Impacts - Test Year Ending June 2022
Present to Proposed Rates

Base Rate Impact

Base % Impact	customers	% customers
0.01% to 1.0%	0	0.00%
1.01% to 2.0%	0	0.00%
2.01% to 3.0%	0	0.00%
3.01% to 4.0%	0	0.00%
4.01% to 5.0%	0	0.00%
5.01% to 6.0%	0	0.00%
6.01% to 7.0%	0	0.00%
7.01% to 8.0%	0	0.00%
8.01% to 9.0%	0	0.00%
9.01% to 10.0%	0	0.00%
10.01% to 11.0%	3	0.00%
11.01% to 12.0%	4	0.00%
12.01% to 13.0%	8	0.00%
13.01% to 14.0%	8	0.00%
14.01% to 15.0%	17	0.00%
15.01% to 16.0%	35	0.00%
16.01% to 17.0%	63	0.01%
17.01% to 18.0%	96	0.01%
18.01% to 19.0%	264	0.02%
19.01% to 20.0%	771	0.07%
20.01% to 21.0%	3,249	0.29%
21.01% to 22.0%	22,820	2.05%
22.01% to 23.0%	949,706	85.14%
23.01% to 24.0%	131,706	11.81%
24.01% to 25.0%	6,594	0.59%
25.01% to 26.0%	132	0.01%
26.01% to 27.0%	7	0.00%
27.01% to 28.0%	1	0.00%
28.01% to 29.0%	0	0.00%
29.01% to 30.0%	1	0.00%
30.01% to 31.0%	0	0.00%
31.01% to 32.0%	0	0.00%
32.01% to 33.0%	0	0.00%
33.01% to 34.0%	0	0.00%
34.01% to 35.0%	0	0.00%
>35.0%	0	0.00%
Total	1,115,485	100.00%

Avg Impact - Base	22.66%
Target	22.79%

Net Day 1 Impact with Adjustor Transfers

Total % Impact	customers	% customers
0.01% to 1.0%	1	0.00%
1.01% to 2.0%	3	0.00%
2.01% to 3.0%	8	0.00%
3.01% to 4.0%	17	0.00%
4.01% to 5.0%	27	0.00%
5.01% to 6.0%	36	0.00%
6.01% to 7.0%	158	0.01%
7.01% to 8.0%	549	0.05%
8.01% to 9.0%	1,758	0.16%
9.01% to 10.0%	4,029	0.36%
10.01% to 11.0%	13,120	1.18%
11.01% to 12.0%	44,336	3.97%
12.01% to 13.0%	100,331	8.99%
13.01% to 14.0%	234,935	21.06%
14.01% to 15.0%	431,137	38.65%
15.01% to 16.0%	188,589	16.91%
16.01% to 17.0%	52,974	4.75%
17.01% to 18.0%	19,439	1.74%
18.01% to 19.0%	8,521	0.76%
19.01% to 20.0%	4,628	0.41%
20.01% to 21.0%	2,668	0.24%
21.01% to 22.0%	1,918	0.17%
22.01% to 23.0%	1,419	0.13%
23.01% to 24.0%	1,335	0.12%
24.01% to 25.0%	3,433	0.31%
25.01% to 26.0%	116	0.01%
26.01% to 27.0%	0	0.00%
27.01% to 28.0%	0	0.00%
28.01% to 29.0%	0	0.00%
29.01% to 30.0%	0	0.00%
30.01% to 31.0%	0	0.00%
31.01% to 32.0%	0	0.00%
32.01% to 33.0%	0	0.00%
33.01% to 34.0%	0	0.00%
34.01% to 35.0%	0	0.00%
>35.0%	0	0.00%
Total	1,115,485	100.00%

Avg Impact - Total	13.75%
Target	13.59%

Lost Fixed Cost Revenue Calculation	Reference		Total
Total Lost Fixed Cost Revenue	(Schedule 3, Line 37 + Schedule 4, Line 37)	**$**	**58,509.31**

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	(C) Totals	(D) Units
	Residential			
	Energy Efficiency Savings			
1.	Current Period		59,014	MWh
2.	Prior Period		53,025	MWh
3.	Verified - Prior Period		49,550	MWh
4.	True-Up Prior Period	(Line 3 - Line 2)	(3,476)	MWh
5.	Cumulative Verified		836,679	MWh
6.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 9)	416,276	
7.	Total Recoverable EE Savings	(Line 1 + Line 4 + Line 5 - Line 6)	475,942	MWh
	Distributed Generation Savings			
8.	Current Period		680,551	MWh
9.	Prior Period		623,714	MWh
10.	Verified - Prior Period		623,733	MWh
11.	True-Up Prior Period	(Line 9 - Line 8)	19	MWh
12.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 16)	159,100	
13.	Total Recoverable DG Savings	(Line 8 + Line 11 - Line 12)	521,470	MWh
14.	Total Recoverable MWh Savings	(Line 6 + Line 11)	997,411	MWh
15.	Residential - Lost Fixed Cost Rate	Decision No. 73183	$ 0.025606	$/kWh
16.	Residential - Lost Fixed Cost Revenue	(Line 12 * Line 13)	$ 25,540	
	C&I			
	Energy Efficiency Savings			
17.	Current Period		69,981	MWh
18.	Excluded MWh reduction		23,827	MWh
19.	Net - Current Period	(Line 15 - Line 16)	46,153	MWh
20.	Prior Period		75,904	MWh
21.	Verified - Prior Period		47,757	MWh
22.	True-Up Prior Period	(Line 19 - Line 18)	(28,148)	MWh
23.	Cumulative Verified		597,964	MWh
24.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 27)	291,566	
25.	Total Recoverable EE Savings	(Line 19 + Line 22 + Line 23 - Line 24)	324,404	MWh
	Distributed Generation Savings			
26.	Current Period		157,739	MWh
27.	MWh DG Savings from Rate Schedules Excluded from LFCR		32,126	MWh
28.	Net - Current Period	(Line 23 - Line 24)	125,613	MWh
29.	Prior Period		121,790	MWh
30.	Verified - Prior Period		111,090	MWh
31.	True-Up Prior Period	(Line 27 - Line 26)	(10,700)	MWh
32.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 34)	87,980	
33.	Total Recoverable DG Savings	(Line 28 + Line 31 - Line 32)	26,933	MWh
34.	Total Recoverable MWh Savings	(Line 22 + Line 29)	351,337	MWh
35.	C&I - Lost Fixed Cost Rate	Decision No. 73183	$ 0.026805	$/kWh
36.	C&I - Lost Fixed Cost Revenue	(Line 30 * Line 31)	$ 9,418	
37.	**Total Lost Fixed Cost Revenue**	**(Line 14 + Line 32)**	**$ 34,957**	

[1] MWh savings transferred into base rates with approval of 2015 TY rate case (Decision No. 76295).

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Calculation
($000)

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	(C) Totals	(D) Units
	Residential			
	Energy Efficiency Savings			
1.	Current Period		38,896	MWh
2.	Prior Period		34,604	MWh
3.	Verified - Prior Period		35,946	MWh
4.	True-Up Prior Period	(Line 3 - Line 2)	1,342	MWh
5.	Cumulative Verified		573,326	MWh
6.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 9)	300,426	MWh
7.	Total Recoverable EE Savings	(Line 1 + Line 4 + Line 5 - Line 6)	313,138	MWh
	Distributed Generation Savings			
8.	Current Period		472,132	MWh
9.	Prior Period		458,210	MWh
10.	Verified - Prior Period		458,224	MWh
11.	True-Up Prior Period	(Line 10 - Line 9)	13	MWh
12.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 16)	114,822	MWh
13.	Total Recoverable DG Savings	(Line 8 + Line 11 - Line 12)	357,323	MWh
14.	Total Recoverable MWh Savings	(Line 7 + Line 13)	670,461	MWh
15.	Residential - Lost Fixed Cost Rate	Decision No. 76295	$ 0.025394	$/kWh
16.	Residential - Lost Fixed Cost Revenue	(Line 14 * Line 15)	$ 17,026	
	C&I			
	Energy Efficiency Savings			
17.	Current Period		82,127	MWh
18.	Excluded MWh reduction		20,686	MWh
19.	Net - Current Period	(Line 17 - Line 18)	61,441	MWh
20.	Prior Period		15,892	MWh
21.	Verified - Prior Period		13,886	MWh
22.	True-Up Prior Period	(Line 21 - Line 20)	(2,006)	MWh
23.	Cumulative Verified		399,114	MWh
24.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 27)	210,423	MWh
25.	Total Recoverable EE Savings	(Line 19 + Line 22 + Line 23 - Line 24)	248,127	MWh
	Distributed Generation Savings			
26.	Current Period		107,756	MWh
27.	MWh DG Savings from Rate Schedules Excluded from LFCR		23,926	MWh
28.	Net - Current Period	(Line 26 - Line 27)	83,831	MWh
29.	Prior Period		82,829	MWh
30.	Verified - Prior Period		75,107	MWh
31.	True-Up Prior Period	(Line 30 - Line 29)	(7,722)	MWh

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Calculation
($000)

32.	Transfer to Base Rates[1]	(2015 Test Year Schedule 3, Line 34)		63,495	MWh
33.	Total Recoverable DG Savings	(Line 28 + Line 31 - Line 32)		12,614	MWh
34.	Total Recoverable MWh Savings	(Line 25 + Line 33)		260,740	MWh
35.	C&I - Lost Fixed Cost Rate	Decision No. 76295	$	0.025030	$/kWh
36.	C&I - Lost Fixed Cost Revenue	(Line 34 * Line 35)	$	6,526	
37.	**Total Lost Fixed Cost Revenue**	**(Line 16 + Line 36)**	**$**	**23,552**	

[1] MWh savings transferred into base rates with approval of 2015 TY rate case (Decision No. 76295).

Demand Side Management Adjustment Charge
Plan of Administration

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1. General Description

This document describes the plan for administering the Demand Side Management Adjustment Charge (DSMAC) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (Commission) in Decision No. 67744, and later revised by the Commission in Decision Nos. 71448, 73183, 74406, 76295, ~~and~~ 78317, 78585 and XXXXX. The DSMAC provides for the recovery of Demand Side Management (DSM) program costs, including energy efficiency (EE) and demand response programs (DR), and ~~energy efficiency~~DSM performance incentives as well as the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of EE savings and distributed generation (DG) determined to have occurred as described herein~~.~~ The lost fixed costs to be recovered include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution. The DSMAC is applied to Standard Offer or Direct Access customer bills as a monthly kilowatt-hour charge (for Residential customers and General Service customers served in accordance with non-demand billed rate schedules), or kilowatt demand charge (for General Service customers served in accordance with demand billed rate schedules), unless the customer's current rate has alternate provisions. The charges will be filed with the Commission annually when APS submits the ~~Energy Efficiency~~DSM Implementation Plan (~~EEIP~~DSMIP) for approval. This will occur ~~June~~ November ~~1~~1st ~~-~~30th of each year. If approved by the Commission, the charge will be effective ~~each~~ the following year beginning with billing cycle 1 of the ~~March~~ October revenue month and will not be prorated.

Recovery of all applicable program costs and incentives will be allowed for all programs that have been approved by the Commission.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Current Period – The most recent adjustment year.



DG Savings – The amount of MWh sales reduced by DG. Where available, APS will use meter data to calculate DG system savings. Each year, APS will use DG production data to calculate the savings. The calculation of DG Savings will consist of the following by class:

- Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.
- Excluded MWh Production: The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the LFCR portion of the DSMAC adjustor rate calculation as shown in Schedule 9 of the compliance filing list.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The Return on Equity (ROE) authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

EE (or DSM) Programs – Any program approved in APS's DSM I~~i~~mplementation Plan.

EE Savings – The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

- Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.
- Current Period: The EE related sales reductions (MWh). Each year, APS will use MER verified data to report EE savings.
- Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of actual EE Savings achieved by customers on Excluded Rate Schedules.

Excluded Delivery Revenue – 50% of any delivery demand (kW) revenue as determined in Decision No. XXXXX and calculated on Schedules 6 and 7.

Lost Fixed Cost Rate – A rate determined at the conclusion of APS's most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue (LFCR) – The amount of fixed costs not recovered by the utility because of EE and DG during the period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Performance Incentives (PI) - Represents a percentage of the net economic customer benefits (benefits minus costs) from approved EE programs based on a graduated scale -that is capped at a maximum of $/kWh of first-year EE savings achieved.

Program Costs (PC) - Allowable expenses include, but are not limited to: program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement DSM programs (EE and DR) that are approved by the Commission in the DSMIP. For those DSM programs that may generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Transition Balance – The Lost Fixed Cost Revenue balance as calculated in compliance during that period per Decision No. 73183 and modified in Decision No. 74202.

True-up (TU) – A reconciling of authorized PC and LFCR amounts from the previous approved Plan.

~~2.~~3.Rate Schedule Applicability

The DSMAC shall be applied monthly to every retail Standard Offer or Direct Access service, unless exempted by Commission order.

4. ~~Allowable Costs~~Performance Incentive~~:~~

~~The types of allowable costs are as follows:~~

~~A. Program Costs (PC) – Allowable expenses include, but are not limited to: Program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement cost effective DSM programs (energy efficiency and demand response) that are approved by the Commission in the EEIP. For those DSM programs that generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.~~



~~B.~~ Performance Incentives (PI) - Represents a percentage of the net economic benefits (benefits minus costs) from approved ~~energy efficiency~~EE ~~programs~~ and DR programs based on a graduated scale that is capped at a maximum $/kWh of first-year savings achieved. ~~percentage of EE and DR PC.~~

Achievement Relative to Annual Goal Approved in APS's DSM~~Energy Efficiency~~ Implementation Plan	Performance Incentive as % of Energy Efficiency and Demand Response Net Benefits	Performance Incentive Cap*
< 85%	0%	Performance Incentive Will Not Exceed $0.0125/kWh Saved
85% to 95%	6%	
96% to 105%	7%	
> 105%	8%	

*The PI cap is based on ~~applies to~~ the annualized incremental first year EE~~energy~~ savings generated plus the equivalent kWh of DR kW savings achieved~~.~~

~~3. Determination of True Up:~~

~~The actual allowable cost recovered for approved DSM programs will be compared to the actual revenues received by the Company through the DSMAC. The True-Up (TU) will be based on the amount in the TU balancing account. This balance will include past period PC, PI and DSMAC revenue collection accruals as of April 30th of the filing year.~~

~~In the event that PC or PI are more or less than DSMAC revenues collected as of the last billing cycle of February, the over or under collection will be subtracted from or added to the DSMAC calculation in the subsequent period. Any over collection will accrue interest charges. Under collections will not accrue interest.~~

~~Illustrative Table of Events~~

~~Date~~	~~Included Items~~
~~7/15/2009~~ ~~DSMAC includes:~~ ~~-~~ ~~-~~	~~File 2010 EEIP with 2010 DSMAC~~ ~~2010 forecast of PC and PI~~ ~~2009 forecast of PC and PI~~ ~~TU balancing account as of the last billing cycle of February~~
~~3/1/2010~~	~~DSMAC start from 2010 EEIP~~
~~6/1/2010~~ ~~DSMAC includes:~~ ~~-~~	~~File 2011 EEIP with 2011 DSMAC~~ ~~2011 forecast of PC and PI~~ ~~TU balancing account as of the last billing cycle of February~~



PLAN OF ADMINISTRATION
DEMAND SIDE MANAGEMENT
ADJUSTMENT CHARGE

~~3/1/2011~~	~~DSMAC start from 2011 EEIP~~
~~6/1/2011~~ ~~DSMAC includes:~~ -	~~File 2012 EEIP with 2012 DSMAC~~ ~~2012 forecast of PC and PI~~ ~~TU balancing account as of the last billing cycle of February~~

~~4.~~5. Determination of the Adjustor Charge

By ~~June 1st~~ November 30th of each year, APS will file a revised DSMAC with supporting documentation in the ~~EEIP~~DSMIP. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods.

The DSMAC calculation will be for purposes of recovering PC, ~~and~~ PI, LFCR under the DSM Program and will be developed based on the following formula:

$$DSMAC = \frac{PC + PI + LFCR + TU + I}{Sales}$$

Where:

PC = Program Costs as defined in section ~~3.~~2 forecast for the ~~upcoming~~ plan year.

PI = Performance Incentives as defined in section ~~3.~~2 forecast for the ~~upcoming~~ plan year.

LFCR = Lost fixed cost recovery as defined in section 2.

TU = Any "true-up" balance ~~as defined in section 4~~.

I = Interest associated on any over recovery of DSMAC costs for the prior period. The interest rate is based on the one-year Nominal Treasury Maturities rate from the Federal Reserve H-15 or its successor publication. The interest rate shall be adjusted annually on the first business day of the calendar year.

Sales = Forecast energy (kWh) sales under applicable electric rate schedules during the Adjustor Period in which this adjustor will be effective.

Adjustor Period = The 12-month period beginning with the first billing cycle during March of the current year and ending with the last billing cycle of February of the next year.

The DSMAC for General Service customers that are billed on demand will be calculated as a per kW charge. The DSMAC for General Service customers that are not billed on demand will be calculated as a per kWh charge. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSMAC.



For residential billing purposes, the DSMAC and the Renewable Energy Adjustment Charge (REAC) are combined and will appear on customer bills as the "Environmental Benefits Surcharge." For general service and other non-residential customer billing, the Company may, but is not required to, provide for such combined billing of the REAC and DSMAC. In any event, each adjustor will be kept separate in the Company's books, records, and reports to the Commission.

a. In the event that PC or LFCR are more or less than DSMAC revenues collected as of the last available period prior to filing, the over or under collection will be included in the TU balancing account. Any over collection will earn interest ~~charges~~. Under collections will not accrue interest.

b. LFCR Annual Incremental Cap will be subject to an annual 1% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR calculated increase exceeds 1% of Applicable Company Revenues, any amount above the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance

~~a.~~c. Earnings Test - –Any requested increase in the Schedule DSMAC adjustment mechanism related to LFCR will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold. If the results of the Earnings Test are higher than the Earnings Test Threshold, the Lost Fixed Cost Revenue recovered through Schedule DSMAC will be limited to the amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule DSMAC in a future year. The results of the Earning Test will only affect recovery with respect to LFCR and not affect any recovery associated with EE or DSM Programs.

6. Compliance Reports

APS will provide comprehensive Compliance Reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

Schedule 1: DSMAC Annual Adjustment
Schedule 2: LFCR Annual Incremental Cap Calculation
Schedule 3: LFCR Calculation
Schedule 4: LFCR Historical Transition
Schedule 5: LFCR Test Year Rate Calculation
Schedule 6: Distribution Revenue Calculation – General Service
Schedule 7: Distribution Revenue Calculation – Residential
Schedule 8: Annual DG Installation Report

Schedule 9: Annual Earnings Test
Schedule 10: Capital Structure

7. Review Process

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Section 5. APS will file an updated adjustor charge each year with its ~~EEIP~~ DSMIP on ~~June~~ November ~~1st~~30th. If approved by the Commission, changes in the DSMAC will go into effect on the first billing cycle of ~~March~~ October of the following year~~in the Adjustor Period~~.

Demand Side Management Adjustment Charge
Plan of Administration

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1. General Description

This document describes the plan for administering the Demand Side Management Adjustment Charge (DSMAC) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (Commission) in Decision No. 67744, and later revised by the Commission in Decision Nos. 71448, 73183, 74406, 76295, 78317, 78585 and XXXXX. The DSMAC provides for the recovery of Demand Side Management (DSM) program costs, including energy efficiency (EE) and demand response programs (DR), and DSM performance incentives as well as the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of EE savings and distributed generation (DG) determined to have occurred as described herein The lost fixed costs to be recovered include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution. The DSMAC is applied to Standard Offer or Direct Access customer bills as a monthly kilowatt-hour charge (for Residential customers and General Service customers served in accordance with non-demand billed rate schedules), or kilowatt demand charge (for General Service customers served in accordance with demand billed rate schedules), unless the customer's current rate has alternate provisions. The charges will be filed with the Commission annually when APS submits the DSM Implementation Plan (DSMIP) for approval. This will occur November 30th of each year. If approved by the Commission, the charge will be effective the following year beginning with billing cycle 1 of the October revenue month and will not be prorated.

Recovery of all applicable program costs and incentives will be allowed for all programs that have been approved by the Commission.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Current Period – The most recent adjustment year.



DG Savings – The amount of MWh sales reduced by DG. Where available, APS will use meter data to calculate DG system savings. Each year, APS will use DG production data to calculate the savings. The calculation of DG Savings will consist of the following by class:

- Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.

Excluded MWh Production: The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the LFCR portion of the DSMAC adjustor rate calculation as shown in Schedule 9 of the compliance filing list.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The Return on Equity (ROE) authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

EE (or DSM) Programs – Any program approved in APS's DSM Implementation Plan.

EE Savings – The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

- Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.
- Current Period: The EE related sales reductions (MWh). Each year, APS will use MER verified data to report EE savings.
- Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of actual EE Savings achieved by customers on Excluded Rate Schedules.

Excluded Delivery Revenue – 50% of any delivery demand (kW) revenue as determined in Decision No. XXXXX and calculated on Schedules 6 and 7.

Lost Fixed Cost Rate – A rate determined at the conclusion of APS's most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential rate class and dividing each by their respective class adjusted test year kWh billing determinants.



Lost Fixed Cost Revenue (LFCR) – The amount of fixed costs not recovered by the utility because of EE and DG during the period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Performance Incentives (PI) - Represents a percentage of the net economic customer benefits (benefits minus costs) from approved EE programs based on a graduated scale that is capped at a maximum of $/kWh of first-year EE savings achieved.
Program Costs (PC) - Allowable expenses include, but are not limited to: program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement DSM programs (EE and DR) that are approved by the Commission in the DSMIP. For those DSM programs that may generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Transition Balance – The Lost Fixed Cost Revenue balance as calculated in compliance during that period per Decision No. 73183 and modified in Decision No. 74202.

True-up (TU) – A reconciling of authorized PC and LFCR amounts from the previous approved Plan.

3. Rate Schedule Applicability

The DSMAC shall be applied monthly to every retail Standard Offer or Direct Access service, unless exempted by Commission order.

4. Performance Incentive

Performance Incentives (PI) - Represents a percentage of the net economic benefits (benefits minus costs) from approved EE and DR programs based on a graduated scale that is capped at a maximum $/kWh of first-year savings achieved.



Achievement Relative to Annual Goal Approved in APS's DSM Implementation Plan	Performance Incentive as % of Energy Efficiency and Demand Response Net Benefits	Performance Incentive Cap*
< 85%	0%	Performance Incentive Will Not Exceed $0.0125/kWh Saved
85% to 95%	6%	
96% to 105%	7%	
> 105%	8%	

*The PI cap is based on the annualized incremental first year EE savings generated plus the equivalent kWh of DR kW savings achieved

5. Determination of the Adjustor Charge

By November 30th of each year, APS will file a revised DSMAC with supporting documentation in the DSMIP. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods.

The DSMAC calculation will be for purposes of recovering PC, PI, LFCR under the DSM Program and will be developed based on the following formula:

$$DSMAC = \frac{PC + PI + LFCR + TU + I}{Sales}$$

Where:

PC = Program Costs as defined in section 2 forecast for the plan year.

PI = Performance Incentives as defined in section 2 forecast for the plan year.

LFCR = Lost fixed cost recovery as defined in section 2.

TU = Any "true-up" balance.

I = Interest associated on any over recovery of DSMAC costs for the prior period. The interest rate is based on the one-year Nominal Treasury Maturities rate from the Federal Reserve H-15 or its successor publication. The interest rate shall be adjusted annually on the first business day of the calendar year.

Sales = Forecast energy (kWh) sales under applicable electric rate schedules during the Adjustor Period in which this adjustor will be effective.

Adjustor Period = The 12-month period beginning with the first billing cycle during March of the current year and ending with the last billing cycle of February of the next year.



The DSMAC for General Service customers that are billed on demand will be calculated as a per kW charge. The DSMAC for General Service customers that are not billed on demand will be calculated as a per kWh charge. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSMAC.

For residential billing purposes, the DSMAC and the Renewable Energy Adjustment Charge (REAC) are combined and will appear on customer bills as the "Environmental Benefits Surcharge." For general service and other non-residential customer billing, the Company may, but is not required to, provide for such combined billing of the REAC and DSMAC. In any event, each adjustor will be kept separate in the Company's books, records, and reports to the Commission.

a. In the event that PC or LFCR are more or less than DSMAC revenues collected as of the last available period prior to filing, the over or under collection will be included in the TU balancing account. Any over collection will earn interest. Under collections will not accrue interest.
b. LFCR Annual Incremental Cap will be subject to an annual 1% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR calculated increase exceeds 1% of Applicable Company Revenues, any amount above the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance
c. Earnings Test - Any requested increase in the Schedule DSMAC adjustment mechanism related to LFCR will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold. If the results of the Earnings Test are higher than the Earnings Test Threshold, the Lost Fixed Cost Revenue recovered through Schedule DSMAC will be limited to the amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule DSMAC in a future year. The results of the Earning Test will only affect recovery with respect to LFCR and not affect any recovery associated with EE or DSM Programs.

6. Compliance Reports

APS will provide comprehensive Compliance Reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

Schedule 1: DSMAC Annual Adjustment
Schedule 2: LFCR Annual Incremental Cap Calculation



Schedule 3: LFCR Calculation
Schedule 4: LFCR Historical Transition
Schedule 5: LFCR Test Year Rate Calculation
Schedule 6: Distribution Revenue Calculation – General Service
Schedule 7: Distribution Revenue Calculation – Residential
Schedule 8: Annual DG Installation Report
Schedule 9: Annual Earnings Test
Schedule 10: Capital Structure

7. Review Process

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Section 5. APS will file an updated adjustor charge each year with its DSMIP on November 30th. If approved by the Commission, changes in the DSMAC will go into effect on the first billing cycle of October of the following year.

Renewable Energy ~~Standard~~ Adjustment ~~Schedule~~Charge
Plan of Administration

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1. General Description

This document describes the plan for administering Arizona Public Service Company's (APS or the Company) Adjustment Schedule REAC-1, Renewable Energy Adjustment Charge (Schedule REAC-1). As authorized for APS ~~Schedule REAC-1 is the tariff required~~ by the Arizona Corporation Commission~~'s~~ (Commission) ~~Renewable Energy Standard and Tariff rules (the Rules) approved~~ in Decision No. ~~69127 (November 14, 2006)~~XXXXX (XXX X, XXX), Schedule REAC-1 ~~and codified in A.A.C. R14-2-1801 *et. seq.*, which~~ provides for the recovery of, both, (1) approved renewable energy program ~~the~~ costs ~~incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.~~[1]in compliance with the Commission's Renewable Energy Standard Tariff (REST) rules and (2) approved capital carrying costs for qualified resources consistent with the APS IRP Action Plan.

2. ~~Allowable Costs~~Definitions

All-Source Request for Proposal (All-Source RFP) – A document issued by APS soliciting proposals from qualified parties in which all types of electric resources or energy storage projects that can meet all or part of the needs described in the RFP will be considered equally.

Allowable Costs – Schedule REAC-1 shall recover the following:

(1) The cost of renewable energy programs included in the Company's annual ~~Renewable Energy Standard Implementation Plan (~~RESTPlan~~)~~, and approved by the Commission, that are not otherwise recovered in base rates or other recovery mechanism. ~~Allowable~~ Costs include, but are not limited to, program development, program implementation, purchased power costs not recovered through the Power Supply Adjustor, customer incentives, customer education and communication, technical assistance and training, marketing, ~~and~~ advertising, administrative and general expense,

(2) The cost of monitoring and evaluation of the programs defined above,

~~[1] The Company's initial Schedule RES was approved by the Commission in Decision No. 70313 (April 28, 2008) and has been revised on an annual basis as described in this Plan of Administration.~~

(3) F~~f~~unds approved by the Commission for Coal Community Transition or similar programs, and

(4) ~~monitoring and evaluation,~~ C~~c~~apital C~~c~~arrying C~~c~~osts for Clean Energy Resources that are in service at the time Schedule REAC-1 rates are approved and are not yet being recovered in base rates or other recovery mechanism, including energy storage and excluding nuclear energy, ~~renewable energy-related capital investments made by APS[2]~~ and other relevant costs where such costs are not otherwise recoverable through an approved RES Implementation Plan.

Applicable Interest – Interest is applied on Balancing Account funds annually at the following rates: any over-collection existing at the time of the adjustor rate calculation will be credited an amount equal to interest at a rate equal to the Company's authorized return on equity (ROE) or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the time of the adjustor rate calculation will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Capital Carrying Costs – Capital carrying costs include (1) a return at the Company's Weighted Average Cost of Capital found by the Commission in the Company's most recent general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits associated with investments being recovered where appropriate and (6) associated operations and maintenance expenses.

Clean Energy Resources – Includes all non-carbon emitting APS-owned resources, including energy storage and excluding nuclear energy.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the Clean Energy Resource portion of the Schedule REAC-1 adjustor rate calculation as shown in Section 5 herein.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The ROE authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

~~[2] Capital carrying costs for any APS renewable energy-related capital investments made in conjunction with projects outside the scope of Decision Nos. 71448, 76295, and 78317 shall not be recovered through Schedule REAC-1 without separate Commission approval.~~

Integrated Resource Planning Action Plan (IRP Action Plan) - The three-year plan required by the Commission's Integrated Resource Planning (IRP) Rules set forth in A.A.C. R14-2-703(H), which is based on the most recent IRP filed by APS and outlines the actions to be taken by the Company on future resource acquisitions.

Renewable Energy Standard and Tariff Rules (REST Rules) – The Commission's Rules, approved in Decision No. 69127 (November 14, 2006) and codified in A.A.C. R14-2-1801 et. seq., which provide for recovery of the costs incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.

Renewable Energy Standard Compliance Report (RES Compliance Report) – The report required by A.A.C. R14-2-1812 et. seq., which is filed on April 1 of each year and describes APS's compliance with the requirements of the REST Rules for the prior calendar year.

Renewable Energy Standard Implementation Plan (RES Plan) – The report required by A.A.C. R14-2-1813 et. seq. as amended by this Plan of Administration, which is filed on November 1 of each year and describes how APS intends to comply with the REST Rules for the next calendar year. The REST Plan will include a description of the Clean Energy Resources to be included in the calculation of the Schedule REAC-1 adjustor rate and will include the calculations showing the derivation of the adjustor rate and the results of the Clean Energy Resources Earnings Test.

Service Schedule 6 – APS's Service Schedule 6, Interconnection Study Services and Fees for Non-FERC Generation Facilities, contains a schedule of fees for feasibility, system impact, and facilities studies for certain generators requesting interconnection to the Company's transmission and/or distribution system. Fees collected by APS for these studies are credited against the Balancing Account for this mechanism as described in Section 4.

3. Clean Energy Resource Eligibility

To be eligible for inclusion in the Schedule REAC-1 adjustor rate, Clean Energy Resources must be consistent with APS's IRP Action Plan and must be acquired through an All-Source RFP process. The All-Source RFP process will be in compliance with the Commission's Procurement Rules set forth in A.A.C. R14-2-705 and 706 and will include the use of an Independent Monitor.

If any eligible Clean Energy Resources generate revenue, such revenue will be included as a credit in the calculation of the Schedule REAC-1 adjustor rate.

Clean Energy Resources to be included in the Schedule REAC-1 adjustor rate will be discussed with stakeholders and interested parties in stakeholder meetings as shown in the Regulatory Timeline (Section 7). A summary of stakeholder meetings and a description of the included resources with relevant supporting documentation will be included in the annual REST Plan.

43. Balancing Account

~~Actual~~ Allowable Costs shall be recorded in a separately maintained Balancing Account. Revenues received by APS through Schedule REAC-1, as well as other relevant revenue (including, but not limited to, ~~forfeited PBI Reservation Deposits and~~payments to APS under

Service Schedule 6 ~~payments~~and any revenue generated by eligible Clean Energy Resources), shall be credited to the Balancing Account.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in the Schedule REAC-1 adjustor rate in the subsequent calendar year.

~~5~~4. Adjustor Components

Schedule REAC-1 shall consist of a monthly kilowatt-hour (kWh) charge applied equally to all Standard Offer and Direct Access service. The kilowatt-hour charge is subject to a monthly ~~surcharge~~adjustor limit calculated for specific customer billing classes as determined by the Company and approved by the Commission.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in Schedule REAC-1 in the subsequent calendar year.

~~6~~5. Determination of the ~~kWh~~ Adjustor Rate and ~~Surcharge~~ Limits for Schedule REAC-1

In accordance with Commission Decision No. 73183, customers who receive an incentive under the Renewable Energy Standard and install their system after July 1, 2012 will pay ~~the~~an applicable monthly ~~surcharge~~ limit. ~~This provision shall be effective in billing cycle 1 after APS reprograms its billing system to accomplish this, or with the March 2013 billing, whichever is first.~~

Schedule REAC-1 shall be revised annually to recover ~~projected~~ Allowable Costs as determined by the Commission through the review and approval process outlined in Section 7 below.~~for the upcoming calendar year, and shall be based on programs and budgets contained in the Company's RES Plan and approved by the Commission.~~ The Schedule REAC-1 kWh rate ~~and surcharge limits~~ shall be designed using projected billing determinants for the ~~same period~~calendar year in which the adjustor rate is expected to become effective. The billing determinants shall include total retail kWh subject to Schedule REAC-1 and the number of customers and associated kWh that are billed under each ~~surcharge~~adjustor limit.

~~7~~6. Review and Approval ~~Process~~

Schedule REAC-1 shall be filed for the upcoming calendar year as part of the Company's REST Plan, which is filed on ~~July~~ November 1st each year as ~~set forth in the Rules~~approved in Decision No. XXXXX. Supporting information for the calculation of ~~the kWh~~ rates shall be provided for Staff and interested parties to review. ~~and surcharge limits as shown in Exhibit 1 to this Plan of Administration shall be provided. Schedule REAC-1 shall be updated to reflect the final approved budget for the upcoming year and an updated projected over and under collection in the Balancing Account through the end of the current year.~~

Prior to filing each year, the Company will review the RES Implementation Plan, including new programs and investments, with Commission Staff and stakeholders. Commission Staff will review the information, along with input and comments from interested parties, and will issue a

report and proposed order for Commission approval.

Once approved by the Commission, the Schedule REAC-1 adjustor rate ~~and surcharge limits~~ will be effective each year beginning with billing cycle 1 of the ~~January~~ October revenue month or as otherwise ordered by the Commission and will not be prorated.

Regulatory Timeline	
Prefile Stakeholder Meeting	Early September
Prefile Stakeholder Meeting if desired	Early October
File RES Implementation Plan	November 1
Stakeholder Meeting	Mid-December
Staff Report Target	Mid-August
Open Meeting Target	September
Rate Implementation	October 1

8. Earnings Test

Any requested increase in the Schedule REAC-1 adjustment mechanism related to Clean Energy Resources will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold.

If the results of the Earnings Test are higher than the Earnings Test Threshold, the Clean Energy Resources capital carrying cost recovered through Schedule REAC-1 will be limited to the amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule REAC-1 in a future year.

9. Schedules

APS's annual REST Plan will include attachments and schedules detailing all calculations that develop the proposed REAC-1 adjustor rates.

Schedules outlining the proposed cost and expected generation from RES-related programs and facilities are based on the templates developed by the REST Format Working Group as required in Decision No. 72737 and approved by Staff.

The REST Plan will include the following Schedules that outline the development of the earnings test as attached to this document:

Earnings Test Schedule 1: Annual Earnings Test
Earnings Test Schedule 2: Capital Structure

APS will continue to file the annual RES Compliance Report on April 1 of each year as required by the REST Rules.

Renewable Energy Adjustment Charge
Plan of Administration

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1. General Description

This document describes the plan for administering Arizona Public Service Company's (APS or the Company) Adjustment Schedule REAC-1, Renewable Energy Adjustment Charge (Schedule REAC-1). As authorized for APS by the Arizona Corporation Commission (Commission) in Decision No. XXXXX (XXX X, XXX), Schedule REAC-1 provides for the recovery of, both, (1) approved renewable energy program costs in compliance with the Commission's Renewable Energy Standard Tariff (REST) rules and (2) approved capital carrying costs for qualified resources consistent with the APS IRP Action Plan.

2. Definitions

All-Source Request for Proposal (All-Source RFP) – A document issued by APS soliciting proposals from qualified parties in which all types of electric resources or energy storage projects that can meet all or part of the needs described in the RFP will be considered equally.

Allowable Costs – Schedule REAC-1 shall recover the following:

(1) The cost of renewable energy programs included in the Company's annual REST Plan, and approved by the Commission, that are not otherwise recovered in base rates or other recovery mechanism. Costs include, but are not limited to, program development, program implementation, purchased power costs not recovered through the Power Supply Adjustor, customer incentives, customer education and communication, technical assistance and training, marketing, advertising, administrative and general expense,
(2) The cost of monitoring and evaluation of the programs defined above,
(3) Funds approved by the Commission for Coal Community Transition or similar programs, and
(4) Capital Carrying Costs for Clean Energy Resources that are in service at the time Schedule REAC-1 rates are approved and are not yet being recovered in base rates or other recovery mechanism, including energy storage and excluding nuclear energy, and other relevant costs where such costs are not otherwise recoverable through an approved RES Implementation Plan.

Applicable Interest – Interest is applied on Balancing Account funds annually at the following rates: any over-collection existing at the time of the adjustor rate calculation will be credited an amount equal to interest at a rate equal to the Company's authorized return on equity (ROE) or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the time of the adjustor rate calculation will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Capital Carrying Costs – Capital carrying costs include (1) a return at the Company's Weighted Average Cost of Capital found by the Commission in the Company's most recent general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits associated with investments being recovered where appropriate and (6) associated operations and maintenance expenses.

Clean Energy Resources – Includes all non-carbon emitting APS-owned resources, including energy storage and excluding nuclear energy.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the Clean Energy Resource portion of the Schedule REAC-1 adjustor rate calculation as shown in Section 5 herein.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The ROE authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

Integrated Resource Planning Action Plan (IRP Action Plan) - The three-year plan required by the Commission's Integrated Resource Planning (IRP) Rules set forth in A.A.C. R14-2-703(H), which is based on the most recent IRP filed by APS and outlines the actions to be taken by the Company on future resource acquisitions.

Renewable Energy Standard and Tariff Rules (REST Rules) – The Commission's Rules, approved in Decision No. 69127 (November 14, 2006) and codified in A.A.C. R14-2-1801 et. seq., which provide for recovery of the costs incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.

Renewable Energy Standard Compliance Report (RES Compliance Report) – The report required

by A.A.C. R14-2-1812 et. seq., which is filed on April 1 of each year and describes APS's compliance with the requirements of the REST Rules for the prior calendar year.

Renewable Energy Standard Implementation Plan (RES Plan) – The report required by A.A.C. R14-2-1813 et. seq. as amended by this Plan of Administration, which is filed on November 1 of each year and describes how APS intends to comply with the REST Rules for the next calendar year. The REST Plan will include a description of the Clean Energy Resources to be included in the calculation of the Schedule REAC-1 adjustor rate and will include the calculations showing the derivation of the adjustor rate and the results of the Clean Energy Resources Earnings Test.

Service Schedule 6 – APS's Service Schedule 6, Interconnection Study Services and Fees for Non-FERC Generation Facilities, contains a schedule of fees for feasibility, system impact, and facilities studies for certain generators requesting interconnection to the Company's transmission and/or distribution system. Fees collected by APS for these studies are credited against the Balancing Account for this mechanism as described in Section 4.

3. Clean Energy Resource Eligibility

To be eligible for inclusion in the Schedule REAC-1 adjustor rate, Clean Energy Resources must be consistent with APS's IRP Action Plan and must be acquired through an All-Source RFP process. The All-Source RFP process will be in compliance with the Commission's Procurement Rules set forth in A.A.C. R14-2-705 and 706 and will include the use of an Independent Monitor.

If any eligible Clean Energy Resources generate revenue, such revenue will be included as a credit in the calculation of the Schedule REAC-1 adjustor rate.

Clean Energy Resources to be included in the Schedule REAC-1 adjustor rate will be discussed with stakeholders and interested parties in stakeholder meetings as shown in the Regulatory Timeline (Section 7). A summary of stakeholder meetings and a description of the included resources with relevant supporting documentation will be included in the annual REST Plan.

4. Balancing Account

Allowable Costs shall be recorded in a separately maintained Balancing Account. Revenues received by APS through Schedule REAC-1, as well as other relevant revenue (including, but not limited to, payments to APS under Service Schedule 6 and any revenue generated by eligible Clean Energy Resources), shall be credited to the Balancing Account.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in the Schedule REAC-1 adjustor rate in the subsequent calendar year.

5. Adjustor Components

Schedule REAC-1 shall consist of a monthly kilowatt-hour (kWh) charge applied equally to all Standard Offer and Direct Access service. The kilowatt-hour charge is subject to a monthly adjustor limit calculated for specific customer billing classes as determined by the Company and approved by the Commission.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in Schedule REAC-1 in the subsequent calendar year.

6. Determination of the Adjustor Rate and Limits for Schedule REAC-1

In accordance with Commission Decision No. 73183, customers who receive an incentive under the Renewable Energy Standard and install their system after July 1, 2012 will pay an applicable monthly limit.

Schedule REAC-1 shall be revised annually to recover Allowable Costs as determined by the Commission through the review and approval process outlined in Section 7 below. The Schedule REAC-1 kWh rate shall be designed using projected billing determinants for the calendar year in which the adjustor rate is expected to become effective. The billing determinants shall include total retail kWh subject to Schedule REAC-1 and the number of customers and associated kWh that are billed under each adjustor limit.

7. Review and Approval

Schedule REAC-1 shall be filed for the upcoming calendar year as part of the Company's REST Plan, which is filed on November 1st each year as approved in Decision No. XXXXX. Supporting information for the calculation of rates shall be provided for Staff and interested parties to review.

Prior to filing each year, the Company will review the RES Implementation Plan, including new programs and investments, with Commission Staff and stakeholders. Commission Staff will review the information, along with input and comments from interested parties, and will issue a report and proposed order for Commission approval.

Once approved by the Commission, the Schedule REAC-1 adjustor rate will be effective each year beginning with billing cycle 1 of the October revenue month or as otherwise ordered by the Commission and will not be prorated.

Regulatory Timeline	
Prefile Stakeholder Meeting	Early September
Prefile Stakeholder Meeting if desired	Early October
File RES Implementation Plan	November 1
Stakeholder Meeting	Mid-December
Staff Report Target	Mid-August
Open Meeting Target	September
Rate Implementation	October 1

8. Earnings Test

Any requested increase in the Schedule REAC-1 adjustment mechanism related to Clean Energy Resources will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold.

If the results of the Earnings Test are higher than the Earnings Test Threshold, the Clean Energy Resources capital carrying cost recovered through Schedule REAC-1 will be limited to the

amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule REAC-1 in a future year.

9. Schedules

APS's annual REST Plan will include attachments and schedules detailing all calculations that develop the proposed REAC-1 adjustor rates.

Schedules outlining the proposed cost and expected generation from RES-related programs and facilities are based on the templates developed by the REST Format Working Group as required in Decision No. 72737 and approved by Staff.

The REST Plan will include the following Schedules that outline the development of the earnings test as attached to this document:

Earnings Test Schedule 1: Annual Earnings Test
Earnings Test Schedule 2: Capital Structure

APS will continue to file the annual RES Compliance Report on April 1 of each year as required by the REST Rules.

RATE RIDER E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Energy Support Program.

DESCRIPTION

The Energy Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the ~~federal~~ Federal ~~poverty~~ Poverty guidelines or those receiving assistance from an APS approved limited income assistance program.

DISCOUNT

The following discount will apply to the Customer's bill, subject to the service details below:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%~~Discount~~	~~25%~~60%	$165	per bill
Greater than 75% up to and including 200%	25%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

~~2. Customers electing to pay with a credit card will receive a bill credit in the amount of their credit card fee applied to their next month's bill.~~

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

~~3.~~4. Customers may not receive discounts under both this rider and Rate Rider E-4 at the same time.

~~4.~~5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Energy Support Program.

DESCRIPTION

The Energy Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the Federal Poverty guidelines or those receiving assistance from an APS approved limited income assistance program.

DISCOUNT

The following discount will apply to the Customer's bill, subject to the service details below:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%	60%	$165	per bill
Greater than 75% up to and including 200%	25%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

4. Customers may not receive discounts under both this rider and Rate Rider E-4 at the same time.

5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Medical Care Equipment Support Program.

DESCRIPTION

The Medical Care Equipment Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program and who require qualifying life-sustaining medical equipment.

DISCOUNT

The following discount will apply to energy purchased under this rate rider:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%~~Discount~~	60%~~35%~~	$165	per bill
Greater than 75% up to and including 200%	35%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

~~2. Customers electing to pay with a credit card will receive a bill credit in the amount of their credit card fee applied to their next month's bill.~~

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

~~3.~~4. Customers may not receive discounts under both this rider and Rate Rider E-3 at the same time.

RATE RIDER E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

~~4.~~5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Medical Care Equipment Support Program.

DESCRIPTION

The Medical Care Equipment Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program and who require qualifying life-sustaining medical equipment.

DISCOUNT

The following discount will apply to energy purchased under this rate rider:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%	60%	$165	per bill
Greater than 75% up to and including 200%	35%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

4. Customers may not receive discounts under both this rider and Rate Rider E-3 at the same time.

5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer Customers who have an Aggregated Peak Load of ~~10~~ 5 MW or more and are served under Rate Schedules E-34, E-35, E32-L, ~~or~~ E-32 TOU L, E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S. ~~An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.~~

Customers must have interval metering, Advanced Metering Infrastructure, or an authorized alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the Customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the Customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of Customer load~~, 100 MW of which will be initially reserved for Customers with single site peak demands of 20 MW or greater and with monthly average load factors above 70%, unless not fully subscribed during the solicitation process~~.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of an application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-X.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this AG-X rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the aggregated actual hourly metered load for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Resource Adequacy: To ensure the reliable operation of the grid, each Generation Service Provider will assure they have acquired sufficient resources to satisfy forecasted future loads and planning reserve margins by meeting the following criteria:

1. Resource ~~s~~Adequacy not purchased from APS must be sourced from a specific generating unit or sourced from a specified aggregation of resources which could be ~~(, and mustinge~~a specified balancing authority area~~)~~.

   ~~Resources must include a specified balancing authority area.~~

2. Resources must be identified in advance as described in the AG-X Program Guidelines.

3. Resource Adequacy is in excess of the host balancing authority area or supplier's existing commitments for reliability planning, and that it is ~~dedicating~~ dedicated to serving APS customer load. The resource must be able to serve APS customer load during reliability events and cannot be curtailed for another entity except in the case of being sourced from a specified aggregation of Balancing Authority resources and the curtailment is pro-rata with native load of sending Balancing Authority Area.

4. The energy being purchased for Resource Adequacy will be delivered to APS at an agreed upon location via firm or high priority transmission as further described in the AG-X Program Guidelines.

5. Resources must include reserves to meet monthly peak load plus a seasonal planning reserve margin as further described in the AG-X Program Guidelines.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, Customers may enroll on a first come first serve basis. After the initial lottery, if necessary, Customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

Eligible Customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor Customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate Customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer must apply for service under this rate rider schedule.

The Company will conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer must select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company must ~~enter into~~enter a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider must provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts~~,~~ and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company will provide transmission, delivery, and network services to the Customer according to normal retail electric service.

aps

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

The Generation Service Provider must provide resource adequacy for their Customer's load by either purchasing from APS or by demonstrating Resource Adequacy seasonally through the process as described AG-X Program Guidelines.

1. During the first year after the effective date of this Schedule, AG-X Customers must meet Resource Adequacy as follows:

    a. By purchasing Resource Adequacy from APS and paying a transition reserve capacity charge of $6.453 per kW; or

    b. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW.

2. After the first year following the effective date of this Schedule, AG-X customers must meet Resource Adequacy as follows:

    a. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW; or~~.~~

    b. By purchasing Resource Adequacy from APS and paying a reserve capacity charge equal to the unbundled generation demand charge of E-34.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs ~~on a monthly basis~~monthly according to the AG-X ~~p~~Program ~~g~~Guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company will bill the Customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The Customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

~~APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, and APS will not request recovery of any unmitigated costs resulting from AG-X, if any, in its next rate case.~~

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company will serve as the scheduling coordinator. The Generation Service Provider must provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT, which now reflects the terms of the CAISO imbalance charges.

ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in subsection i above, ~~i)~~ GSPs would pay a penalty of $3 per MWh.

iii. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again ~~in a subsequent month,~~ within 12 months from the date of the first notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of the GSP's termination, the Customer will be required to secure a replacement GSP within 60 days, and will be subject to the terms listed in "Default of the ~~third~~ Third-~~p~~Party ~~g~~Generation ~~p~~Provider".

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

DEFAULT OF THE THIRD--PARTY GENERATION PROVIDER

~~In the event that~~If the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days of such notification. Prior to execution of any new power contract, the Company will provide the required power to the Customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the Company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the Customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customers may return to the Company's Standard Generation Service under their applicable retail rate schedules if: (1) they provide one ~~or more~~ years notice to the Company and are receiving Company provided RA; (2) they provide three years notice to the Company where they are receiving GSP provided RA; or (~~2~~3) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to ~~the~~ Customers under the following conditions. The Company may elect to provide a~~the~~ Customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain ~~1~~ one year notice if the ~~c~~Customer had previously been receiving Company provided RA or three years notice if the ~~c~~Customer had previously been receiving GSP provided RA, at which time the Customer returns to the Company's Standard Generation Service under its~~their~~ applicable retail rate schedule. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the Customer's applicable retail rate schedule will continue to apply except as follows:

1. The ~~-~~generation charges will not apply;

2. Adjustment Schedule PSA-1 will not apply;

3. Adjustment Schedule EIS will not apply; and

4. The applicable proportionate part of any taxes or governmental impositions, which are or may in the future be assessed based on any of the following will be applied to the Customer's bill ~~on the basis of~~:

   a. The Company's gross revenues ~~of the Company and/or~~.

   b. ~~t~~The price or revenue from the electric energy or service sold ~~and/or~~.

   ~~4.~~c. ~~t~~The volume of energy generated or purchased for sale ~~and/or~~or sold hereunder~~, will be applied to the Customer's bill~~.

Schedule AG-X charges determined and billed by the Company include:

1. A monthly administrative management fee of $0.~~00171~~ 00164 per kWh applied to the Customer's billed kWh;

2. A monthly reserve capacity charge ~~of $5.248 per kW~~ applied to 100% of the Customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);

3. Returning Customer charge, where applicable, as described herein;

4. Generation Service Provider Default charge, where applicable, as described herein.

~~These charges and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.~~

Schedule AG-X Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges will be charged at a rate within the minimum and maximum limits as follows:

   a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
   b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The

determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.

c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges will be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with ~~Section~~ section ~~IV~~ iii under ~~imbalance~~ Imbalance ~~services~~Services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to, the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

AG-X customers that aggregated accounts to meet the ~~10~~5 MW minimum load size eligibility requirements may add new accounts not previously on their application if their load falls below the ~~10~~5 MW threshold because of participation in energy efficiency programs.

AG-X customers may grow up to 10% beyond their original allocation in the program.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer Customers who have an Aggregated Peak Load of 5 MW or more and are served under Rate Schedules E-34, E-35, E32-L, E-32 TOU L, E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S.

Customers must have interval metering, Advanced Metering Infrastructure, or an authorized alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the Customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the Customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of Customer load.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of an application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-X.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this AG-X rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.



RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the aggregated actual hourly metered load for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Resource Adequacy: To ensure the reliable operation of the grid, each Generation Service Provider will assure they have acquired sufficient resources to satisfy forecasted future loads and planning reserve margins by meeting the following criteria:

1. Resource Adequacy not purchased from APS must be sourced from a specific generating unit or sourced from a specified aggregation of resources which could be a specified balancing authority area.

2. Resources must be identified in advance as described in the AG-X Program Guidelines.

3. Resource Adequacy is in excess of the host balancing authority area or supplier's existing commitments for reliability planning, and that it is dedicated to serving APS customer load. The resource must be able to serve APS customer load during reliability events and cannot be curtailed for another entity except in the case of being sourced from a specified aggregation of Balancing Authority resources and the curtailment is pro-rata with native load of sending Balancing Authority Area.

4. The energy being purchased for Resource Adequacy will be delivered to APS at an agreed upon location via firm or high priority transmission as further described in the AG-X Program Guidelines.

5. Resources must include reserves to meet monthly peak load plus a seasonal planning reserve margin as further described in the AG-X Program Guidelines.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, Customers may enroll on a first come first serve basis. After

the initial lottery, if necessary, Customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

Eligible Customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor Customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate Customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer must apply for service under this rate rider schedule.

The Company will conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer must select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company must enter a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider must provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company will provide transmission, delivery, and network services to the Customer according to normal retail electric service.

The Generation Service Provider must provide resource adequacy for their Customer's load by either purchasing from APS or by demonstrating Resource Adequacy seasonally through the process as described AG-X Program Guidelines.

1. During the first year after the effective date of this Schedule, AG-X Customers must meet Resource Adequacy as follows:

    a. By purchasing Resource Adequacy from APS and paying a transition reserve capacity charge of $6.453 per kW; or

b. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW.

2. After the first year following the effective date of this Schedule, AG-X customers must meet Resource Adequacy as follows:

   a. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW; or

   b. By purchasing Resource Adequacy from APS and paying a reserve capacity charge equal to the unbundled generation demand charge of E-34.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs monthly according to the AG-X Program Guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company will bill the Customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The Customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company will serve as the scheduling coordinator. The Generation Service Provider must provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.



RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT, which now reflects the terms of the CAISO imbalance charges.

ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in subsection i above, GSPs would pay a penalty of $3 per MWh.

iii. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again within 12 months from the date of the first notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of the GSP's termination, the Customer will be required to secure a replacement GSP within 60 days, and will be subject to the terms listed in "Default of the Third-Party Generation Provider".

DEFAULT OF THE THIRD-PARTY GENERATION PROVIDER

If the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days of such notification. Prior to execution of any new power contract, the Company will provide the required power to the Customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the Company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the Customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customers may return to the Company's Standard Generation Service under their applicable retail rate schedules if: (1) they provide one year notice to the Company and are receiving Company provided RA; (2) they provide three years notice to the Company where they are



RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

receiving GSP provided RA; or (3) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to Customers under the following conditions. The Company may elect to provide a Customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain one year notice if the Customer had previously been receiving Company provided RA or three years notice if the Customer had previously been receiving GSP provided RA, at which time the Customer returns to the Company's Standard Generation Service under its applicable retail rate schedule. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the Customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;

2. Adjustment Schedule PSA-1 will not apply;

3. Adjustment Schedule EIS will not apply; and

4. The applicable proportionate part of any taxes or governmental impositions, which are or may in the future be assessed based on any of the following will be applied to the Customer's bill:

    a. The Company's gross revenues.

    b. The price or revenue from the electric energy or service sold.

    c. The volume of energy generated or purchased for sale or sold hereunder.

Schedule AG-X charges determined and billed by the Company include:

1. A monthly administrative management fee of $0.00164 per kWh applied to the Customer's billed kWh;

2. A monthly reserve capacity charge applied to 100% of the Customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);

3. Returning Customer charge, where applicable, as described herein;

4. Generation Service Provider Default charge, where applicable, as described herein.



RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

Schedule AG-X Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges will be charged at a rate within the minimum and maximum limits as follows:

    a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
    b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.
    c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges will be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with section iii under Imbalance Services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider,

including but not limited to, the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

AG-X customers that aggregated accounts to meet the 5 MW minimum load size eligibility requirements may add new accounts not previously on their application if their load falls below the 5 MW threshold because of participation in energy efficiency programs.

AG-X customers may grow up to 10% beyond their original allocation in the program.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all service schedules and rate schedules including but not limited to rider and adjustor schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. **Application for Service**

Before supplying service, APS will verify the identity of Applicant. Applicants may be required to appear at the Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and the Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 **Grounds for Refusal of Service** – APS may refuse service if any of the following conditions exist:

(A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to the Company.

(B) A condition exists that, in the Company's judgment, is unsafe or hazardous.

(C) The Applicant has failed to meet the Company's security-deposit requirements outlined in Section 3.

(D) The Applicant is known to be in violation of a Company Tariff.

(E) The Applicant fails to furnish the funds, service, equipment, ~~rightsofway~~rights-of-way or easements required to serve the Applicant that APS has specified as a condition for providing service.

(F) The Applicant falsifies his or her identity for the purpose of obtaining service.

(G) Service is already being provided at the address for which the Applicant is requesting service.



(H) A prior Customer, who will reside at or benefit from service at the Applicant's P~~p~~remises, owes APS a delinquent bill for the same class of service from the same or a prior service address.

(I) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

2. **Service Establishment**

A Service Establishment Charge of $0.00 for residential or $0.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month. All service establishment requests are subject to availability; there is no guarantee that the Company will have the ability to provide service establishment, re-establishment, or reconnection of service on same-day requests or requests made outside of regular business hours. For situations where the Company is unable to complete same-day or after-hours requests, service establishment will be scheduled for the next available business day.

2.1 **Multiple Connects –** If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service Establishment Charge once for every two Delivery Points.

2.2 **After-hours Connect –** The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $0.00 for residential with standard metering, $0.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 **Same-Day Connect –** The Customer must also pay a same-day connect charge of $0.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by the Company, waive the same-day fee.

2.4 **Non-Standard Service Request –** The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when the Customer requests



services that do not meet the definition of Service Establishment as defined in A.A.C. R14-2-203.D.3 and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives the Company uses to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 **Waiving of Service Establishment Charge** – The Company may waive the Service Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with the Company.

3. **Establishing Credit, Security Deposits and other forms of Credit Assurance**
When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to provide a security deposit to secure payment of bills for service.

3.1 **Residential Establishment of Credit** – APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

(A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.

(B) The Company receives an acceptable credit rating, as determined by the Company, for the Applicant from a credit-rating agency used by the Company.

(C) The Applicant can produce a letter regarding verification of credit from an electric utility that provided service of a comparable nature to the Applicant within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.

(D) If, in lieu of a security deposit, the Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.



3.2 **Nonresidential Establishment of Credit** – All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

(A) The Applicant had service of a comparable nature with the Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.

(B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 **General Deposits Guidelines** – If a security deposit is required, a separate deposit may be required for each service location.

(A) A Customer's security deposit will not preclude the Company from terminating an agreement for service or suspending service if the Customer fails to meet service-agreement obligations.

(B) The Company may choose to accept less than the full deposit required at the time ~~of~~ service is ~~establishment~~ established based on the Customer's financial condition.

(C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, the Company may require the Customer to establish or reestablish a security deposit.

3.4 **Residential Security Deposits** – Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by the Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 **Nonresidential Security Deposits** – Nonresidential security deposits will not exceed two and one-half times the Customer's maximum monthly billing as estimated by the Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by the



Company based on the results of using a credit-scoring worksheet. The Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 **Deposit Interest –** Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 **Deposit Refunds –** If the Customer terminates all service with the Company, the Customer's security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days of the Customer's final bill due date.

3.8 **Residential security deposits** or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

(A) **Nonresidential security deposits** and noncash deposits on file with the Company will be reviewed after 24 months of service and will be returned if:

(1) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(2) The Customer's financial condition does not warrant an extension of the security deposit.

4. **Rates**

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 **Rate Selection –** APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, the Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 **Rate Information –** APS will ~~provide~~make available, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in the Company's Tariff affecting those Customers.



4.3 **Optional Rates** – Optional rate schedules are available for certain classes of service. After establishing service, a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. For non-residential customers, ~~No~~ no further rate schedule changes may be made within the succeeding ~~12 month~~12-month period~~.~~ If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

~~4.3~~4.4 The Company may, at its discretion, place a Customer on an available rate schedule (consistent with the existing meter's ability to measure service) while the Company seeks satisfactory and unassisted access to the Company's equipment if the Customer refuses to allow meter access. Please also see 7.3(E).

5. **Billing**

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at the Company's option.

5.1 **Payment of Bills** – The Customer is responsible for paying bills until service is ordered discontinued and the Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services are involved, until the Company has had reasonable time to process the disconnect request.

5.2 **Failure to Receive Bills or Notices** (including notices of disconnection) which have been properly placed in the United States mail to the Customer's last address on file or sent by or through alternative methods of communications~~billing forms~~, such as electronic mail to the Customer's last email address on file, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the C~~c~~ustomer of their obligations.

5.3 **Incentive for Electronic Payments** – A monthly incentive of $0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

5.4 **Billing Errors** – When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

5.5 **Corrected Charges for Overbilling –** Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by the Company.

5.6 **Corrected Charges for Underbilling –** Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and ~~is~~ will not be limited to three or six months ~~as applicable~~.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by the Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with the Customer to establish a payment plan that is acceptable to the Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

5.7 The Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. **Collection Policy**

The following collection policies apply to all Customer accounts:

6.1 **Delinquent Bills –** All bills rendered by the Company are due and payable no later than 21 calendar days from the billing date. Any payment not received within this time frame is delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of the Company's termination procedure. The Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.



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6.2 **Late Charges –** All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 **Transfer of Outstanding Bills –** If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to the Company, the Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, the Company has the right to collect the full amount owed from any one of the Customers.

6.4 **Dishonored Payments –** If the Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, the Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to the Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The Company will waive the $15.00 Dishonored Payment fee if the Customer has not, in the previous 12 months, had a dishonored payment.

(C) The tender of a dishonored payment does not relieve the Customer of the obligation to pay the Company under the original terms of the bill, nor does it defer the Company's right to terminate the Customer's service for nonpayment of bill(s).

(D) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, the Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 **Collection Agency Referrals –** All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, the Customer may be responsible for the associated collection-agency fees incurred.



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7. **Termination of Service**

7.1 To avoid termination of service: The Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to the Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company. APS may also require payment of Same-Day and After-Hours charges prior to restoring service.

7.3 **Termination of Service ~~With~~ with Notice** – APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if the Company has met the notice requirements established by the Arizona Corporation Commission:

(A) The Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.

(B) ~~A~~ The Customer's failure to pay a Delinquent Bill for services provided by Company.

(C) The Customer's breach of a written contract for service.

(D) The Customer's failure to comply with the Company's deposit requirements.

(E) The Customer's failure to provide the Company with satisfactory and unassisted access to the Company's equipment.

(F) When necessary to comply with an order of any governmental agency having jurisdiction.

(G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the P~~p~~remises.

(H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.

(I) The Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

(J) When the Company learns of the unauthorized resale of utility equipment or services by the Customer.

7.4 **Termination of Service Without Notice** – Notwithstanding subsections 7.1, 7.3, 7.5, and 7.7, the Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

(A) An obvious hazard to the safety or health of the Customer, the general population or the utility's personnel or facilities;



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(B) The Company has evidence of Meter Tampering or fraud related to the Customer or the service address; or

(C) The Customer fails to comply with the curtailment procedures imposed by the Company during a supply shortage.

7.5 **Termination of Service for Dishonored Payment** – Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, ~~or~~ certified funds, or cashier's check. If Customer has already received a final notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

(A) When the Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.

(B) When the Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 **Termination ~~Process~~ Charges** – **The** Company will require payment of a Field Call Charge of $0.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

7.7 **Residential Service Termination Process**

(A) Except as provided in subsection 7.4, the Company shall not disconnect residential service to a Customer:

(1) From June 1 through October 15;

(2) If the C~~c~~ustomer has paid at least half of the C~~c~~ustomer's Delinquent Bill balance within the last 25 days;

(3) Due to a C~~c~~ustomer's failure to pay the disputed portion of a bill if the C~~c~~ustomer has complied with A.A.C. R14-2-212(B);

(4) If the C~~c~~ustomer's Delinquent Bill balance is less than or equal to $300.00; or

(5) If the C~~c~~ustomer can establish, on an annual basis, through medical documentation that, in the opinion of a licensed medical practitioner:



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a. Termination would be especially dangerous to the health of the Cc~~c~~ustomer or a permanent resident residing at the Cc~~c~~ustomer's service address; or
b. If life support equipment used in the home is dependent on utility service for operation of such apparatus.

(B) The Company shall provide notice of the following, using the Cc~~c~~ustomer's preferred method of communication on file, to a Cc~~c~~ustomer whose service would be disconnected except for subsection 7.7(A)(1):
(1) The ~~customer~~ Customer would have been disconnected if not for subsection 7.7(A)(1);
(2) The reason ~~that~~ the Company is not permitted to disconnect service;
(3) The ~~customer's~~ Customer's continued financial responsibility for the charges accruing to the account for energy used;
(4) The potential actions the ~~customer~~ Customer may take to prevent the disconnection of service when subsection 7.7(A)(1) no longer applies; and
(5) The requirement to enter into a payment plan as specified in subsection (D).

(C) The Company shall not disconnect residential service unless the Company's office is open to the public on the day of disconnection and the day following the day of disconnection.

(D) A ~~customer~~ Customer with a Delinquent Bill balance of over $75 whose service disconnection was prevented by subsection 7.7(A)(1) shall be automatically placed on a six-month deferred payment arrangement prior to beginning the service termination process once the no disconnect period set forth in subsection 7.7(A)(1) has ended. The Company shall not impose any late fees or interest on any past due amounts that accrued during the no disconnect period.

(E) If a residential Customer is delinquent on an account and has a cash deposit with the Company, the Company shall use the deposit to pay the delinquent amount before disconnecting service, then allow the ~~residential customer~~ Customer time to repay the deposit in installments over a period of six months.

8. **Metering & Metering Equipment**

8.1 **Standard Metering** – The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All ~~customers~~ Customers will be served using the Company's standard metering equipment unless:



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(A) ~~t~~The ~~customer~~ Customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) T~~t~~he ~~customer~~ Customer meets all eligibility requirements for non-standard metering and ~~voluntarily~~ requests non-standard metering.

8.2 **Non-Standard Metering** – The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to ~~customers~~ Customers who select a non-standard meter.

8.3 **Non-Standard Metering Eligibility** – Only residential ~~customers~~Customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or ~~customers~~ Customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 **Non-Standard Metering Charges** – The following charges will apply when a ~~customer~~ Customer ~~voluntarily~~ requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for ~~customers~~ Customers with existing AMI meter.

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see Section 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 **Discontinuation of Non-Standard Metering** – The Company may replace a non-standard meter with a standard meter, without notifying the ~~customer~~ Customer prior to replacement, under any of the following conditions:

(A) The Company employees observe or have evidence of a safety hazard to employees, ~~customers~~Customers, or the Company's or ~~customer~~ Customer property.

(B) The Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) The Company has evidence of unauthorized resale of electricity.

(D) The Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to the Company equipment, and physical threats such as weapons or dogs.



~~(E)~~ All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 **Measuring Customer Service** – All energy sold to the Customer by the Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by the Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 **Meter Rereads** – When requested by a Customer, APS will reread the C~~c~~ustomer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 **Meter Testing** – APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon a Customer's request. If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 **Meter Test Charge** – If the Meter is found to be within the plus or minus 3% limit, the Company may charge the Customer $44.00 plus applicable adjustments for a Customer-requested Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

(A) The ~~company~~ Company will waive the Meter Test Charge if the Customer has not, within the previous 12 months, requested a meter test that was found to be within the plus or minus 3% limit.

8.10 **Meter Tampering** – If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion, will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by the Company.



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9. **Service Installations & Metering –** The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to the Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

   9.1 **Customer Equipment –** The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for the Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by the Company. In circumstances where a clearance is not required by law, the Company may require the Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to the Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining the Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

   9.2 **Special Meter-Reading Device –** Where a Customer requests, and the Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

   9.3 **Totalized Metering and Billing –** The Company normally meters and bills each site separately. But, at the Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at the Company's option, be considered a single site as specified in the Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

   9.4 **Service Connections –** The Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

      (A) For overhead service, the Point of Delivery is where the Company's service conductors terminate at the Customer's weatherhead or bus rider.

      (B) For underground service, the Point of Delivery is where the Company's service conductors terminate in the Customer's or development's service



equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing the Company's underground service conductors.

(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and the Company, only authorized employees or agents of the Company ~~or the Load Serving~~are permitted to make and energize the connection between the Company's service wires and the Customer's service entrance conductors. APS employees must carry the Company-issued identification that they will show on request.

10. **Customer Obligations**

10.1 **Load Characteristics** – The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customers must meet power factor requirements as specified in the applicable rate schedules.

10.2 **Easements** – All suitable Easements or rights-of-way required by the Company for any portion used~~of an extension~~ to serve ~~a~~ Customer(s), which ~~is~~ are either on sites owned, leased, or otherwise controlled by the Customer(s) or developer(s), or other property required for the Company's use~~extension~~, will be furnished in the Company's name by the Customer(s) without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All Easements or rights-of-way granted to, or obtained on behalf of, the Company will contain terms and conditions that are acceptable to the Company. Notwithstanding the terms of a written ~~Easment~~Easement or right-of-way, ~~W~~when the Company discovers that a~~the~~ Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, a ~~11.~~djacent to or within an Easement or right-of-way or adjacent to Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with the Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, the Company will notify the Customer or the Customer's agent and may take whatever actions are necessary



to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. The Company will notify the Customer in writing ~~of the violations~~before taking such action.

10.3 **Access for Repair, Maintenance and Service Restoration –** The Company's authorized agents must have satisfactory unassisted, ~~24~~ 24 ~~hour~~ hour-~~a~~ a-day, seven days a week access to the Company's equipment located on the Customer's sites for the purpose of repair, maintenance, and service-restoration work that the Company may need to perform.

10.4 **Access for Install, Inspect, Read, or Remove –** The Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all ~~reasonable~~ hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 **Trip Charge –** A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

(A) The ~~company~~ Company will waive the Trip Charge if, within the last 12 months, there have not been any instances where an authorized Company representative traveled to a site and was unable to complete the Customer's service request because of lack of access to the Point of Delivery.

10.6 **Six Months No Access –** If the Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then the Company has sufficient cause to terminate service or deny any rate options where, in the Company's opinion, access is required.

10.7 **Remedies –** The remedy for unassisted access will be at APS's discretion and may include the installation by the Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for the Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

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11. **Company Obligations**

11.1 **Customer-Specific Information** – Customer-specific information will not be released without the Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with the Company if the goods or services will help the Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to the Company.

11.2 **Service Voltage** – The Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208.F. The Company may deliver service for special applications at higher voltages, with prior approval from the Company's Engineering Department and in accordance with the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. **Limitations on Liability of Company**

12.1 **General Liability**

(A) The Company will not be responsible for any third-party claims against the Company that arise from a Customer's use of the Company's electric services or the Company's provision of electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

(B) A Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

(C) Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to a Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of



the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

(D) In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue, loss of current or prospective business opportunities, lost profits and lost rent) of any kind whatsoever regardless of the cause or foreseeability thereof.

(E) The Company will not be responsible in any occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

12.2 **Service Interruptions**

(A) The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 12.3(A) or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment or to eliminate the possibility of damage to the Company's property or to the person or property of others.

(B) Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this interruption or limitation will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

(C) The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.



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(D) In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(E) The use of electric energy upon the Customer's Premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

12.3 **Force Majeure**

(A) Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

(1) flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

(2) accident or explosion;

(3) war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

(4) acts of God;

(5) interference of civil and/or military authorities;

(6) strikes, lockouts or other labor difficulties;

(7) vandalism, sabotage or malicious mischief;

(8) usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

(9) breakage, failure, or accidents to equipment or facilities; or

(10) lack, limitation or loss of electrical or fuel supply; or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

(B) A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

(C) Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

~~12.1 **Service Interruptions** Company is not liable to the Customer for any damages caused by Load Serving Electric Service Provider's equipment or failure to perform, fluctuations, interruptions, or curtailment of electric service, except where caused by Company's willful misconduct or gross negligence.~~

~~(A) Company may, without incurring any liability, suspend the Customer's electric service for periods reasonably required to permit Company to accomplish repairs to, or changes in, any Company's facilities.~~

~~(B) The Customer is responsible for protecting Customer's own sensitive equipment from harm caused by variations or interruptions in power supply.~~

~~(C) If a national emergency or local disaster results in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.~~

~~12.2 **Use of Service or Apparatus** The Customer will save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or their use on the Customer's side of the Point of Delivery. Company has the right to suspend or terminate service if Company learns of service use by the Customer under hazardous conditions.~~

~~(A) The Customer will exercise all reasonable care to prevent loss or damage to Company property installed on the Customer's site for the purpose of supplying service to the Customer. The Customer is responsible for payment for loss or damage to Company property on the Customer's site arising from neglect, carelessness, or misuse, and will reimburse Company for the cost of necessary repairs or replacements.~~

~~(B) The Customer is responsible for payment of any equipment damage or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by passing the Meter.~~

~~(C) The Customer is responsible for notifying APS of any failure in Company's equipment.~~

~~12.3 **Removal of Facilities** Upon termination of service, Company may, without liability for injury or damage, dismantle and remove its facilities,~~



~~installed for the purpose of supplying service to the Customer, and Company will have no further obligation to serve the Customer.~~

13. **Successors and Assigns –** Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and the Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by the Company.

14. **Warranty –** There are no understanding, agreements, representations, or warranties, expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by the Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of the Company in connection with sales and deliveries.

15. **Direct Access Service –** *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*
    15.1 **Direct Access Service Request (DASR) –** A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (~~"~~ESP~~")~~ submitting the DASR each time the Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.
    15.2 **Direct Access Service –** Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.
    (A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.
    (B) If a Customer returning to Standard Offer Service, in accordance with the rules, regulations and orders of the Commission, was not given the required



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notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer ~~s~~Service.

(C) Unpaid charges incurred before the Customer selects Direct Access Service will not delay the Customer's request for Direct Access Service. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to the Company under the Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, the Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where the Company is the MRSP, the Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of the Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 **Direct Access Deposits –** If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under the Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that the Company is providing bundled electric service.

15.4 **Direct Access and Company Equipment**

(A) **Meters –** A Meter Service Provider (MSP) or its authorized agents may remove the Company's metering equipment under the Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to the Company or returned damaged will result in charge(s) to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) **Lock-rings –** The Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and



conditions of the Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If the Company must replace 10% of the issued keys within any 12-month period because of loss by the MSP's agent, the Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock-ring keys must be returned to the Company within five working days if the MSP or its authorized agents are:

(1) No longer permitted to remove Company Meters under the conditions of the Company's Schedule 10;

(2) No longer authorized by the Arizona Corporation Commission to provide services; ort

(3) The ESP Agreement has been terminated.

(C) **Site Meetings** – If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. The Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If the Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Date is the date the statement was created either in electronic or paper form as shown on the bill regardless of the postmark, mailing, or electronic transmittal date.

Billing Month means the period between any two regular readings of the utility's Meters at approximately ~~30~~ 30-day intervals. [A.A.C. R14-2-201-(5)]



Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company Holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, Christmas Eve, Christmas Day, and New Year's Eve.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (22 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(~~12~~13)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on a Customer's property. [A.A.C. R-14-2-201-(~~13~~14)]

Easement means the right to use~~a property owner ("Grantor") grants the right to use the owner's~~ land owned by~~to~~ another party by grant or as allowed by law. An easement gives the Company the right to have Company lines or facilities on property not owned by the Company. This allows the Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity and for other purposes. The owner~~Grantor~~ may continue to use the land in ~~along~~ the easement as provided by a written easement or by law~~within certain limitations~~.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and the Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not ~~apply~~apply, and service will automatically be



transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with the Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(~~23~~27)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(~~25~~29)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from the Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(30~~26~~)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(31~~27~~)]

On-site means on a single Premises served by the Company's facilities.

Premises means all of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by alleys, canals, streets, railways, or other public rights-of-way.

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(3~~5~~1)]

Working Day means a weekday~~s~~ (during normal business hours) that is not designated as a Company holiday.

~~**Tariffs** mean the documents filed with the Arizona Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products. [A.A.C. R14-2-201(42)]~~



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Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$0.00	2
Nonresidential Service Establishment Charge	$0.00	2
After hours Charge – Residential Standard Metering	$0.00	2.2
After hours Charge – Residential Non-Standard Metering	$0.00	2.2
After hours Charge – Nonresidential	$164.00	2.2
Same Day Connect Charge	$0.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
Electronically Transmitted Payment Discount	($0.48)	5.3
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$0.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering – Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9
Trip Charge – Residential	$22.00	10.5
Trip Charge – Nonresidential	$26.00	10.5

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Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all service schedules and rate schedules including but not limited to rider and adjustor schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. **Application for Service**

Before supplying service, APS will verify the identity of Applicant. Applicants may be required to appear at the Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and the Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 **Grounds for Refusal of Service** – APS may refuse service if any of the following conditions exist:

(A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to the Company.

(B) A condition exists that, in the Company's judgment, is unsafe or hazardous.

(C) The Applicant has failed to meet the Company's security-deposit requirements outlined in Section 3.

(D) The Applicant is known to be in violation of a Company Tariff.

(E) The Applicant fails to furnish the funds, service, equipment, rights-of-way or easements required to serve the Applicant that APS has specified as a condition for providing service.

(F) The Applicant falsifies his or her identity for the purpose of obtaining service.

(G) Service is already being provided at the address for which the Applicant is requesting service.



(H) A prior Customer, who will reside at or benefit from service at the Applicant's Premises, owes APS a delinquent bill for the same class of service from the same or a prior service address.

(I) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

2. **Service Establishment**

A Service Establishment Charge of $0.00 for residential or $0.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month. All service establishment requests are subject to availability; there is no guarantee that the Company will have the ability to provide service establishment, re-establishment, or reconnection of service on same-day requests or requests made outside of regular business hours. For situations where the Company is unable to complete same-day or after-hours requests, service establishment will be scheduled for the next available business day.

2.1 **Multiple Connects –** If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service Establishment Charge once for every two Delivery Points.

2.2 **After-hours Connect –** The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $0.00 for residential with standard metering, $0.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 **Same-Day Connect –** The Customer must also pay a same-day connect charge of $0.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by the Company, waive the same-day fee.

2.4 **Non-Standard Service Request –** The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when the Customer requests



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services that do not meet the definition of Service Establishment as defined in A.A.C. R14-2-203.D.3 and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives the Company uses to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 **Waiving of Service Establishment Charge** – The Company may waive the Service Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with the Company.

3. **Establishing Credit, Security Deposits and other forms of Credit Assurance**
When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to provide a security deposit to secure payment of bills for service.

3.1 **Residential Establishment of Credit** – APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

(A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.

(B) The Company receives an acceptable credit rating, as determined by the Company, for the Applicant from a credit-rating agency used by the Company.

(C) The Applicant can produce a letter regarding verification of credit from an electric utility that provided service of a comparable nature to the Applicant within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.

(D) If, in lieu of a security deposit, the Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.



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3.2 **Nonresidential Establishment of Credit –** All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

(A) The Applicant had service of a comparable nature with the Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.

(B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 **General Deposits Guidelines –** If a security deposit is required, a separate deposit may be required for each service location.

(A) A Customer's security deposit will not preclude the Company from terminating an agreement for service or suspending service if the Customer fails to meet service-agreement obligations.

(B) The Company may choose to accept less than the full deposit required at the time service is established based on the Customer's financial condition.

(C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, the Company may require the Customer to establish or reestablish a security deposit.

3.4 **Residential Security Deposits –** Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by the Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 **Nonresidential Security Deposits –** Nonresidential security deposits will not exceed two and one-half times the Customer's maximum monthly billing as estimated by the Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by the Company based on the results of using a credit-scoring worksheet. The Company



will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 **Deposit Interest –** Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 **Deposit Refunds –** If the Customer terminates all service with the Company, the Customer's security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days of the Customer's final bill due date.

3.8 **Residential security deposits** or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

(A) **Nonresidential security deposits** and noncash deposits on file with the Company will be reviewed after 24 months of service and will be returned if:

(1) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(2) The Customer's financial condition does not warrant an extension of the security deposit.

4. **Rates**

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 **Rate Selection –** APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, the Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 **Rate Information –** APS will make available, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in the Company's Tariff affecting those Customers.



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4.3 **Optional Rates** – Optional rate schedules are available for certain classes of service. After establishing service, a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. For non-residential customers, no further rate schedule changes may be made within the succeeding 12-month period If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

4.4 The Company may, at its discretion, place a Customer on an available rate schedule (consistent with the existing meter's ability to measure service) while the Company seeks satisfactory and unassisted access to the Company's equipment if the Customer refuses to allow meter access. Please also see 7.3(E).

5. **Billing**

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at the Company's option.

5.1 **Payment of Bills** – The Customer is responsible for paying bills until service is ordered discontinued and the Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services are involved, until the Company has had reasonable time to process the disconnect request.

5.2 **Failure to Receive Bills or Notices** (including notices of disconnection) which have been properly placed in the United States mail to the Customer's last address on file or sent by or through alternative methods of communications, such as electronic mail to the Customer's last email address on file, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the Customer of their obligations.

5.3 **Incentive for Electronic Payments** – A monthly incentive of $0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

5.4 **Billing Errors** – When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.



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5.5 **Corrected Charges for Overbilling –** Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by the Company.

5.6 **Corrected Charges for Underbilling –** Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and will not be limited to three or six months.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by the Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with the Customer to establish a payment plan that is acceptable to the Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

5.7 The Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. **Collection Policy**

The following collection policies apply to all Customer accounts:

6.1 **Delinquent Bills –** All bills rendered by the Company are due and payable no later than 21 calendar days from the billing date. Any payment not received within this time frame is delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of the Company's termination procedure. The Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.



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6.2 **Late Charges –** All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 **Transfer of Outstanding Bills –** If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to the Company, the Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, the Company has the right to collect the full amount owed from any one of the Customers.

6.4 **Dishonored Payments –** If the Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, the Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to the Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The Company will waive the $15.00 Dishonored Payment fee if the Customer has not, in the previous 12 months, had a dishonored payment.

(C) The tender of a dishonored payment does not relieve the Customer of the obligation to pay the Company under the original terms of the bill, nor does it defer the Company's right to terminate the Customer's service for nonpayment of bill(s).

(D) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, the Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 **Collection Agency Referrals –** All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, the Customer may be responsible for the associated collection-agency fees incurred.



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7. **Termination of Service**

7.1 To avoid termination of service: The Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to the Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company. APS may also require payment of Same-Day and After-Hours charges prior to restoring service.

7.3 **Termination of Service with Notice** – APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if the Company has met the notice requirements established by the Arizona Corporation Commission:

(A) The Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.

(B) The Customer's failure to pay a Delinquent Bill for services provided by Company.

(C) The Customer's breach of a written contract for service.

(D) The Customer's failure to comply with the Company's deposit requirements.

(E) The Customer's failure to provide the Company with satisfactory and unassisted access to the Company's equipment.

(F) When necessary to comply with an order of any governmental agency having jurisdiction.

(G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the Premises.

(H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.

(I) The Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

(J) When the Company learns of the unauthorized resale of utility equipment or services by the Customer.

7.4 **Termination of Service Without Notice** – Notwithstanding subsections 7.1, 7.3, 7.5, and 7.7, the Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

(A) An obvious hazard to the safety or health of the Customer, the general population or the utility's personnel or facilities;



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(B) The Company has evidence of Meter Tampering or fraud related to the Customer or the service address; or

(C) The Customer fails to comply with the curtailment procedures imposed by the Company during a supply shortage.

7.5 **Termination of Service for Dishonored Payment** – Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, certified funds, or cashier's check. If Customer has already received a final notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

(A) When the Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.

(B) When the Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 **Termination Charges – The** Company will require payment of a Field Call Charge of $0.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

7.7 **Residential Service Termination Process**

(A) Except as provided in subsection 7.4, the Company shall not disconnect residential service to a Customer:

(1) From June 1 through October 15;

(2) If the Customer has paid at least half of the Customer's Delinquent Bill balance within the last 25 days;

(3) Due to a Customer's failure to pay the disputed portion of a bill if the Customer has complied with A.A.C. Rl4-2-212(B);

(4) If the Customer's Delinquent Bill balance is less than or equal to $300.00; or

(5) If the Customer can establish, on an annual basis, through medical documentation that, in the opinion of a licensed medical practitioner:



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a. Termination would be especially dangerous to the health of the Customer or a permanent resident residing at the Customer's service address; or
b. If life support equipment used in the home is dependent on utility service for operation of such apparatus.

(B) The Company shall provide notice of the following, using the Customer's preferred method of communication on file, to a Customer whose service would be disconnected except for subsection 7.7(A)(1):
(1) The Customer would have been disconnected if not for subsection 7.7(A)(1);
(2) The reason the Company is not permitted to disconnect service;
(3) The Customer's continued financial responsibility for the charges accruing to the account for energy used;
(4) The potential actions the Customer may take to prevent the disconnection of service when subsection 7.7(A)(1) no longer applies; and
(5) The requirement to enter into a payment plan as specified in subsection (D).

(C) The Company shall not disconnect residential service unless the Company's office is open to the public on the day of disconnection and the day following the day of disconnection.

(D) A Customer with a Delinquent Bill balance of over $75 whose service disconnection was prevented by subsection 7.7(A)(1) shall be automatically placed on a six-month deferred payment arrangement prior to beginning the service termination process once the no disconnect period set forth in subsection 7.7(A)(1) has ended. The Company shall not impose any late fees or interest on any past due amounts that accrued during the no disconnect period.

(E) If a residential Customer is delinquent on an account and has a cash deposit with the Company, the Company shall use the deposit to pay the delinquent amount before disconnecting service, then allow the Customer time to repay the deposit in installments over a period of six months.

8. **Metering & Metering Equipment**

8.1 **Standard Metering –** The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All Customers will be served using the Company's standard metering equipment unless:

(A) The Customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or



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(B) The Customer meets all eligibility requirements for non-standard metering and requests non-standard metering.

8.2 **Non-Standard Metering –** The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to Customers who select a non-standard meter.

8.3 **Non-Standard Metering Eligibility –** Only residential Customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or Customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 **Non-Standard Metering Charges** – The following charges will apply when a Customer requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for Customers with existing AMI meter.

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see Section 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 **Discontinuation of Non-Standard Metering –** The Company may replace a non-standard meter with a standard meter, without notifying the Customer prior to replacement, under any of the following conditions:

(A) The Company employees observe or have evidence of a safety hazard to employees, Customers, or the Company's or Customer property.

(B) The Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) The Company has evidence of unauthorized resale of electricity.

(D) The Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to the Company equipment, and physical threats such as weapons or dogs.

All terms and conditions in Section 7, regarding termination of service, will also apply.



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8.6 **Measuring Customer Service** – All energy sold to the Customer by the Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by the Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 **Meter Rereads** – When requested by a Customer, APS will reread the Customer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 **Meter Testing –** APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon a Customer's request. If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 **Meter Test Charge –** If the Meter is found to be within the plus or minus 3% limit, the Company may charge the Customer $44.00 plus applicable adjustments for a Customer-requested Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

(A) The Company will waive the Meter Test Charge if the Customer has not, within the previous 12 months, requested a meter test that was found to be within the plus or minus 3% limit.

8.10 **Meter Tampering –** If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion, will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by the Company.

9. **Service Installations & Metering –** The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of



service, or total service cannot be measured through one Meter according to the Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

9.1 **Customer Equipment –** The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for the Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by the Company. In circumstances where a clearance is not required by law, the Company may require the Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to the Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining the Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

9.2 **Special Meter-Reading Device –** Where a Customer requests, and the Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

9.3 **Totalized Metering and Billing –** The Company normally meters and bills each site separately. But, at the Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at the Company's option, be considered a single site as specified in the Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

9.4 **Service Connections –** The Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

(A) For overhead service, the Point of Delivery is where the Company's service conductors terminate at the Customer's weatherhead or bus rider.

(B) For underground service, the Point of Delivery is where the Company's service conductors terminate in the Customer's or development's service equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing the Company's underground service conductors.



(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and the Company, only authorized employees or agents of the Company are permitted to make and energize the connection between the Company's service wires and the Customer's service entrance conductors. APS employees must carry the Company-issued identification that they will show on request.

10. **Customer Obligations**

10.1 **Load Characteristics –** The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customers must meet power factor requirements as specified in the applicable rate schedules.

10.2 **Easements –** All suitable Easements or rights-of-way required by the Company for any portion used to serve Customer(s), which are either on sites owned, leased, or otherwise controlled by the Customer(s) or developer(s), or other property required for the Company's use, will be furnished in the Company's name by the Customer(s) without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All Easements or rights-of-way granted to, or obtained on behalf of, the Company will contain terms and conditions that are acceptable to the Company. Notwithstanding the terms of a written Easement or right-of-way, when the Company discovers that a Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or adjacent to Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with the Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, the Company will notify the Customer or the Customer's agent and may take whatever actions are necessary to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. The Company will notify the Customer in writing before taking such action.



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10.3 **Access for Repair, Maintenance and Service Restoration –** The Company's authorized agents must have satisfactory unassisted, 24-hour-a-day, seven days a week access to the Company's equipment located on the Customer's sites for the purpose of repair, maintenance, and service-restoration work that the Company may need to perform.

10.4 **Access for Install, Inspect, Read, or Remove –** The Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 **Trip Charge –** A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

(A) The Company will waive the Trip Charge if, within the last 12 months, there have not been any instances where an authorized Company representative traveled to a site and was unable to complete the Customer's service request because of lack of access to the Point of Delivery.

10.6 **Six Months No Access –** If the Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then the Company has sufficient cause to terminate service or deny any rate options where, in the Company's opinion, access is required.

10.7 **Remedies –** The remedy for unassisted access will be at APS's discretion and may include the installation by the Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for the Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.



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11. **Company Obligations**

11.1 **Customer-Specific Information** – Customer-specific information will not be released without the Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with the Company if the goods or services will help the Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to the Company.

11.2 **Service Voltage** – The Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208.F. The Company may deliver service for special applications at higher voltages, with prior approval from the Company's Engineering Department and in accordance with the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. **Limitations on Liability of Company**

12.1 **General Liability**

(A) The Company will not be responsible for any third-party claims against the Company that arise from a Customer's use of the Company's electric services or the Company's provision of electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

(B) A Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

(C) Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to a Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of



the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

(D) In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue, loss of current or prospective business opportunities, lost profits and lost rent) of any kind whatsoever regardless of the cause or foreseeability thereof.

(E) The Company will not be responsible in any occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

12.2 **Service Interruptions**

(A) The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 12.3(A) or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment or to eliminate the possibility of damage to the Company's property or to the person or property of others.

(B) Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this interruption or limitation will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

(C) The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.



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(D) In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(E) The use of electric energy upon the Customer's Premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

12.3 **Force Majeure**

(A) Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

(1) flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;
(2) accident or explosion;
(3) war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;
(4) acts of God;
(5) interference of civil and/or military authorities;
(6) strikes, lockouts or other labor difficulties;
(7) vandalism, sabotage or malicious mischief;
(8) usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;
(9) breakage, failure, or accidents to equipment or facilities; or
(10) lack, limitation or loss of electrical or fuel supply; or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

(B) A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.



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(C) Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

13. **Successors and Assigns –** Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and the Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by the Company.

14. **Warranty –** There are no understanding, agreements, representations, or warranties, expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by the Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of the Company in connection with sales and deliveries.

15. **Direct Access Service** – *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*
    15.1 **Direct Access Service Request (DASR) –** A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (ESP submitting the DASR each time the Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.
    15.2 **Direct Access Service –** Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.
    (A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.
    (B) If a Customer returning to Standard Offer Service, in accordance with the rules, regulations and orders of the Commission, was not given the required



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notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer Service.

(C) Unpaid charges incurred before the Customer selects Direct Access Service will not delay the Customer's request for Direct Access Service. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to the Company under the Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, the Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where the Company is the MRSP, the Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of the Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 **Direct Access Deposits –** If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under the Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that the Company is providing bundled electric service.

15.4 **Direct Access and Company Equipment**

(A) **Meters –** A Meter Service Provider (MSP) or its authorized agents may remove the Company's metering equipment under the Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to the Company or returned damaged will result in charge(s) to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) **Lock-rings –** The Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and



conditions of the Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If the Company must replace 10% of the issued keys within any 12-month period because of loss by the MSP's agent, the Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock-ring keys must be returned to the Company within five working days if the MSP or its authorized agents are:

(1) No longer permitted to remove Company Meters under the conditions of the Company's Schedule 10;
(2) No longer authorized by the Arizona Corporation Commission to provide services; ort
(3) The ESP Agreement has been terminated.

(C) **Site Meetings –** If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. The Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If the Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Date is the date the statement was created either in electronic or paper form as shown on the bill regardless of the postmark, mailing, or electronic transmittal date.

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30-day intervals. [A.A.C. R14-2-201-(5)]



Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company Holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, Christmas Eve, Christmas Day, and New Year's Eve.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (22 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(13)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on a Customer's property. [A.A.C. R-14-2-201-(14)]

Easement means the right to use land owned by another party by grant or as allowed by law. An easement gives the Company the right to have Company lines or facilities on property not owned by the Company. This allows the Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity and for other purposes. The owner may continue to use the land in the easement as provided by a written easement or by law.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and the Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not apply, and service will automatically be transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with the Company.



Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(27)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(29)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from the Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(30)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(31)]

On-site means on a single Premises served by the Company's facilities.

Premises means all of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by alleys, canals, streets, railways, or other public rights-of-way.

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(35)]

Working Day means a weekday (during normal business hours) that is not designated as a Company holiday.



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Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$0.00	2
Nonresidential Service Establishment Charge	$0.00	2
After hours Charge – Residential Standard Metering	$0.00	2.2
After hours Charge – Residential Non-Standard Metering	$0.00	2.2
After hours Charge – Nonresidential	$164.00	2.2
Same Day Connect Charge	$0.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
Electronically Transmitted Payment Discount	($0.48)	5.3
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$0.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering – Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9
Trip Charge – Residential	$22.00	10.5
Trip Charge – Nonresidential	$26.00	10.5

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

General Description

This schedule establishes the terms and conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1. **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2. **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

1.3. **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.4. **Conversion** means converting overhead distribution facilities to underground facilities.

1.5. **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.

1.6. **Doubtful Permanency means** a customer who, in the opinion of the Company, is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.7. **Economic Feasibility** means a determination by Company that the estimated annual

revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8. **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9. **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment, installed solely to serve an individual applicant or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10. **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11. **Irrigation** means water pumping service.

1.12. **Limited-Income Multi-Unit Residential Housing** means multi-unit housing that primarily leases to lower income or very low-income residents as defined by the U.S. Department of Housing and Urban Development HUD Public Housing Program.

1.13. **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicant's successors in interest with Company approval, which approval will not be unreasonably withheld.

1.14. **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.15. **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.16. **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.17. **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.18. **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or

seasonal in nature. Permanency at the service location may be established by such things as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.19. **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.20. **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.21. **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.

1.22. **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.23. **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.24. **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.25. **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed

1.26. **Arizona Rural Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.27. **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Arizona Rural Municipality, and where the Arizona Rural Municipality will be the lease-holder for future permanent applicants.

1.28. **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.29. **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.30. **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

~~1.30.~~1.31. **Voltage** for purposes of APS rates, secondary voltage is considered 600v and below. Primary is considered 601v up to 69kv. Transmission is 69kv and above. For clearances or engineering purposes refer to APS's Electric Service Requirements

Manual.

2. General Provisions for Service

2.1. **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), Temporary Applicants (Section 13), and Doubtful Permanency Customers (Section 14).

2.2. **Schedule of Charges** - An applicant requesting an extension will be provided a sketch showing the Extension Facilities and a~~n itemized cost~~ quote based on the Schedule of Charges or other applicable details. ~~The Schedule of Charges is attached to this Service Schedule as Attachment 1.~~ When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Subdivisions 100 lots or greater or that require feeder, backbone and/or major infrastructure to serve development~~Extension Facilities for General Service applicants with estimated demand loads of three megawatts or greater, or that require in aggregate 3,000 kVA of transformer capacity or greater~~.

(D) Extension Facilities for General Service applicants that require feeder, backbone and/or major infrastructure or specialized equipment to serve project~~that require three-phase transformer installations greater than the sizes noted in the Schedule of Charges~~.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments, Residential Lot Sale, Corporate Business and Industrial Park Developments, or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.

2.3. **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all ~~earth work~~earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

(C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

(D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

2.4. **Refunds** – The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) The Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High-Rise Development will be five years from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family

Developments will be five years and will start three months from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

2.5. **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6. **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1. Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on an allowance ~~free footage basis~~ under the following conditions:

(A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site plan has been approved and recorded in the county having jurisdiction.

~~(C) The total footage of the Extension Facilities (primary, secondary, service) does not exceed 750 feet per applicant or $10,000; or~~

~~(D)~~(C) The total cost of the Extension Facilities (primary, secondary, service), as determined by Company, is less than $10,000 per applicant.

3.2. All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3. Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5. The ~~footage allowance of 750 feet and~~allowance ~~the~~ cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

~~3.6. Examples of the application of Section 3.1 can be found in Attachment 2 – Free Footage Illustrative Example.~~

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SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

4. Residential Subdivision Developments

4.1. Extension Facilities will be installed to Residential Subdivision developments of four or more homes in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If the final approved plat is different from what was originally submitted to the Company, it may cause delays and additional cost for redesign.

4.2. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition or organizational structure of developer.

4.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights.

4.6. The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date the Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7. Examples of the application of Section 4 can be found in Attachment ~~3~~ 1 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1. Extension Facilities will be installed to residential "Lot Sale" developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

~~(A)~~(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2. ~~The development plat has been approved and recorded in the county having jurisdiction.~~ The cost of extending service to applicant will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost Estimate ~~depending on the scope of the project~~.

5.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

5.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan

5.5. Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1. Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2. The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate ~~based on the scope of the project~~.

6.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

6.4. Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

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SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

7. Residential Multi-Family Developments

7.1. Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2. The cost of extending service to applicant will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost estimate ~~depending on the scope of the project~~.

7.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition, or organizational structure of applicant.

7.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights etc.

7.6. The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8. General Service Provisions

8.1. Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9. Basic General Service

9.1. Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2. The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3. The cost for Extension Facilities that require feeder, backbone, major infrastructure, or specialized equipment to serve the project~~installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity~~, will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost Estimate ~~depending on the scope of the project~~.

~~9.4. The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project Specific Cost Estimates.~~

~~9.5.~~9.4. Economic Feasibility Analysis for Basic General Service Applicants - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant’s Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company’s then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant’s Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant’s Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an

adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(E) Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(F) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10. High Rise Developments

10.1. Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS' Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

10.3. Economic Feasibility Analysis for High Rise Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to

advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4. Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

11. Mixed-Use Developments

11.1. Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

11.3. Economic Feasibility Analysis for Mixed Use Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4. Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

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SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

12. Corporate Business & Industrial Park Developments

12.1. Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2. The cost of installing Extension Facilities will be determined in accordance with ~~the Schedule of Charges,~~ a Project-Specific Cost Estimate~~, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project~~.

~~12.3. The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project Specific Cost Estimate depending on the scope of the project.~~

~~12.4. The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project Specific Cost Estimates.~~

~~12.5.~~12.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

~~12.6.~~12.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

~~12.7.~~12.5. Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13. Temporary Applicants

13.1. Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be

determined by Company based on a Project-Specific Cost Estimate.

13.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3. When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14. Doubtful Permanency Customers

14.1. When, in the opinion of Company, permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

14.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15. Municipalities and Other Governmental Agencies

15.1. Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2. The effective date for projects enacted under this provision for purposes of Section 2.4 will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16. Change in Applicant's Service Requirements

16.1. Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or

combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17. Relocations, Conversions and Upgrades of Company Facilities

17.1. **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2. **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3. **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

18. Additional Primary Feed or Specialized Equipment

18.1. When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate.

Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19. Unusual Circumstances

19.1. In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20. Abnormal Loads

20.1. Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21. Master Metering

21.1. **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion is individually metered by Company.

21.2. **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable under the following conditions:

(A) For Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care or;

(B) For Limited-Income Multi-Unit Residential Housing that uses solar power in a "behind-the-meter" application

21.3. **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4. **Conversion from master meter to individually metered system** - Company will convert its facilities from a master metered system to a permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22. Voltage

22.1. All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2. Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.

23. Point of Delivery

23.1. For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

23.2. For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.

23.3. For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

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SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

24. Easements

24.1. Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension will be obtained by applicant and provided to Company in Company's name without cost to or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25. Grade Modifications

25.1. If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26. Measurement and Location

26.1. Measurement must be along the proposed route of construction.
26.2. Construction will be on public streets, roadways, highways, or easements acceptable to Company.
26.3. The Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27. Agreements

27.1. **Study and Design Agreements** - Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.
27.2. **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be

credited to the cost of the extension; otherwise, the payment will be non-refundable.

27.3. **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28. Applicant Construction of Company Distribution Facilities

28.1. Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2. This option is not available for the following:

(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.

(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3. All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4. Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5. Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6. A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7. For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8. Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.



29. Settlement of Disputes

29.1. Any dispute between the applicant or prospective applicant and the Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30. Policy Exceptions

30.1. This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission.

(A) The following exceptions have been approved for Rural Municipality applicants:

i. Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by permanent applicants.

ii. The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

iii. The refund eligibility period for Rural Municipal Business Developments will be 7 years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

iv. Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the 7th year refundable period. Any unrefunded advance balance paid at the start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement.

v. Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

vi. The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports

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SERVICE SCHEDULE 3
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the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

vii. Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

(B) The following exceptions for sections 3, 7, 9, 10, and 11 have been approved for Hopi and Navajo applicants for the extension of electric service to residential and commercial buildings within the Navajo Nation and the Hopi Reservation that are in the APS service territory.

i. APS distribution facilities will be extended up to 2,000 feet at no cost to such applicants.

ii. Applicants requiring distribution facilities extending more than 2,000 feet will pay the amount as calculated through the schedule of charges or project specific costs for any distribution facilities after the initial 2,000 feet from existing APS distribution consistent with the application sections of this schedule.

SCHEDULE OF CHARGES

Description	Rate	Unit
Single Family Underground	$ 8.40	Per foot
Single Family Overhead	$ 22.40	Per foot
Residential Subdivision*	$ 12.26	Per foot
General Service and Commercial, Single Phase, Underground	$ 16.06	Per foot
General Service and Commercial, Single Phase, Overhead	$ 28.12	Per foot
General Service and Commercial, Three Phase, Underground	$ 42.81	Per foot
General Service and Commercial, Three Phase, Overhead	$ 59.04	Per foot
Single Phase Pole Interset (pole set in existing line)	$ 7,133.39	Each
Three Phase Pole Interset (pole set in existing line)	$ 9,378.39	Each
*Residential Subdivision projects with 100 or more lots will be determined via project specific costs.		

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

~~Attachment 1~~

~~Schedule of Charges – Single Phase~~

~~APS Schedule 3 Rev 15, Line Extension Schedule of Charges~~

Single Phase	OH Primary	UG Primary			OH Secondary	UG Secondary	
	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Junction Cabinet	OH/UG Transition	Secondary Pole	OH/UG Secondary Transition	J Box
	$18.74	$6.12	$920	$4,242	$883	$2,607	$1,397	$131.00
	Each Installation							
Pole Interset	$10,430.00							
OVERHEAD Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$3,475	$5.93				
	200 Amp	50kVA	$4,004	$7.88				
	400 Amp	50kVA	$4,004	$7.88				
	600 Amp	75kVA	$4,945	$13.22				
	800 Amp	100kVA	$6,010	$18.57				
UNDERGROUND Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$4,099	$5.19				
	200 Amp	50kVA	$4,526	$6.82				
	400 Amp	50kVA	$4,526	$6.82				
	600 Amp	75kVA	$5,164	$13.79				
	800 Amp	100kVA	$5,962	$15.71				

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine
3) Pad Mount Junction Cabinet is a single phase termination cabinet.
4) Primary OH cost per foot is for one phase and a neutral or two phases and no neutral; includes poles, framing, 2R conductor.
5) Charges for services are based on linear footage from Transformer to SES regardless of the number of sets. J Boxes not included in footage cost.
6) All footages to be calculated by linear footages.
7) Transition is from the OH line to the UG line; includes wire down pole and accessories. Pole NOT included.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

~~APS Schedule 3 Rev 15, Line Extension Schedule of Charges~~

~~Attachment 1~~

~~Schedule of Charges – Three Phase~~

	Overhead				Underground						
FEEDER Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (3-750)	Pull Box (3-750)	Manhole (3-750)	Cost per Circuit Foot (6-750)	Pull Box (6-750)	Manhole (6-750)	Pad Mount Switch Gear	Cost per Circuit Foot 1100A Cable (3-1100)	Cost per Circuit Foot 1100A Cable (6-
	$32.74	$28.25	$4,472	$14,391	$55.72	$7,898	$20,077	$21964	$32.28	$63.80
		Each Installation			Each Installation				Each Installation	Each Installation
OH/UG Transition		$7,079			$8,549				$7,129	$8,649
		Each Installation								
Pole Interset	$11,352									
	Overhead		Underground							
PRIMARY Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (3-1/0T)	Cost per Circuit Foot (3-4/0T)	Pull Box	Pad Mount Switch Gear					
	$24.38	$18.20	$22.41	$1,676	$21,964					
		Each Installation	Each Installation							
OH/UG Transition		$3,133	$3,259							
		Each Installation								
Pole Interset	$11,352									

Overhead										
SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft		
200 Amp	3-25kVA	$8,774		$6.21	200 Amp	3-50kVA	$12,239		$6.21	
200 Amp	3-50kVA	$10,361		$6.21						
400 Amp	3-50kVA	$10,361		$8.40	400 Amp	3-75kVA	$14,423		$8.40	
600 Amp	3-50kVA	$10,361		$11.33	600 Amp	3-100kVA	$16,454		$11.33	
800/1000 Amp	3-75kVA	$13,166		$22.82	600 Amp	3-167kVA	$18,908		$22.82	
Underground Pad mount										Transition
SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft		OH/UG Secondary Transition
200 Amp	112.5kVA	$7,555		$7.51	200 Amp	112.5kVA	$11296		$7.51	
					400 Amp	150kVA	$12,365		$13.71	
400 Amp	112.5kVA	$7,555		$13.71	400 Amp	225kVA	$12,518		$13.71	$882.69
600 Amp	150kVA	$12,726		$19.81	600 Amp	300kVA	$15,383		$23.08	
800 Amp	225kVA	$14,259		$39.59	800 Amp	500kVA	$11051		$39.59	
1000 Amp	225kVA	$14,259		$39.59	1000 Amp	500kVA	$11051		$39.59	
1200 Amp	300kVA	$15,603		$39.59	1200 Amp	750kVA	$22,243		$59.27	
1600 Amp	500kVA	$20,538		$79.04	1600 Amp	1000kVA	$25,957		$79.04	
2000 Amp	500kVA	$20,544		$79.04	2000 Amp	1000kVA	$25,963		$79.04	
2500 Amp	750kVA	$28,626		$138.35	2500 Amp	1500kVA	$38,007		$118.60	
3000 Amp	750kVA	$28,638		$138.35	3000 Amp	1500kVA	$31,019		$118.60	
3000 Amp	1000kVA	$33,843		$177.80	3000 Amp	2000kVA	$46,244		$177.80	

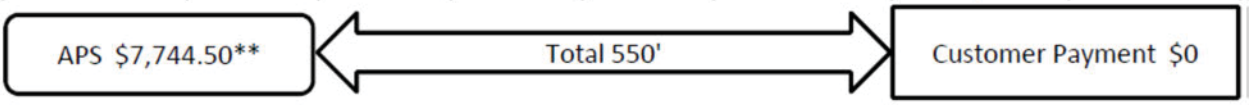
1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will le summed to determine charges.
3) For Multiple services out of one three phase transformer; the service cost will be determined by each SES and the transformer cost will be determined from the combined total of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000 amps.
4) Overhead feeder cost per foot is for 3/0 and above, including 477 & 795 conductors.
5) UG Primary circuit footage is 3 cables making up 3 phase; 2 circuits is parallel conductors.
6) Charges for services are based on linear footage from transformer to SES regardless for the number of sets.
7) Transition is from the OH line to the UG line: includes wire down pole and accessories. Pole NOT included.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

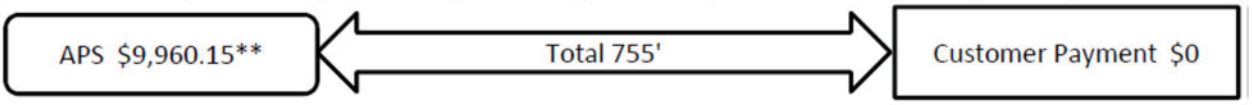
~~**Attachment 2**~~

~~**Examples to Section 3* Free Footage Illustrative Example**~~

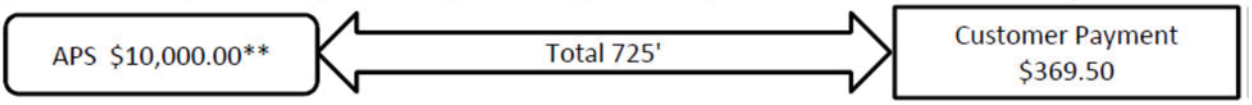
	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 1	**500**	**$15.00**	**50**	**$ 4.89**	**550**	**$ 7,744.50**	**$ -**



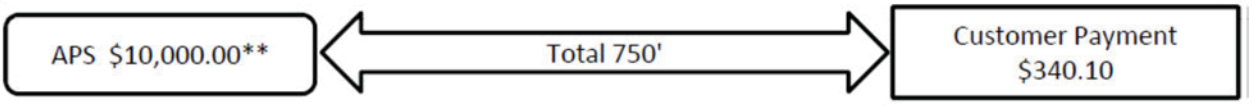
	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 2	**620**	**$ 15.00**	**135**	**$ 4.89**	**755**	**$ 9,960.15**	**$ -**



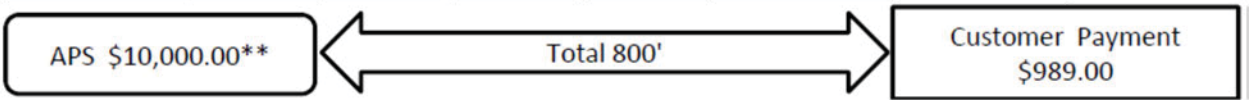
	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 3	**675**	**$ 15.00**	**50**	**$ 4.89**	**725**	**$ 10,369.50**	**$ 369.50**



	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 4	**660**	**$ 15.00**	**90**	**$ 4.89**	**750**	**$ 10,340.10**	**$ 340.10**



	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 5	**700**	**$ 15.00**	**100**	**$ 4.89**	**800**	**$ 10,989.00**	**$ 989.00**



~~*Scenarios do not reflect all components required for a complete project. **APS portion does not include cost of transformer.~~

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SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment ~~3~~1
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

General Description

This schedule establishes the terms and conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1. **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2. **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

1.3. **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.4. **Conversion** means converting overhead distribution facilities to underground facilities.

1.5. **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.

1.6. **Doubtful Permanency means** a customer who, in the opinion of the Company, is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.7. **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding

taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8. **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9. **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment, installed solely to serve an individual applicant or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10. **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11. **Irrigation** means water pumping service.

1.12. **Limited-Income Multi-Unit Residential Housing** means multi-unit housing that primarily leases to lower income or very low-income residents as defined by the U.S. Department of Housing and Urban Development HUD Public Housing Program.

1.13. **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicant's successors in interest with Company approval, which approval will not be unreasonably withheld.

1.14. **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.15. **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.16. **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.17. **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.18. **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things

as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.19. **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.20. **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.21. **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.

1.22. **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.23. **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.24. **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.25. **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed

1.26. **Arizona Rural Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.27. **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Arizona Rural Municipality, and where the Arizona Rural Municipality will be the lease-holder for future permanent applicants.

1.28. **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.29. **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.30. **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

1.31. **Voltage** for purposes of APS rates, secondary voltage is considered 600v and below. Primary is considered 601v up to 69kv. Transmission is 69kv and above. For clearances or engineering purposes refer to APS's Electric Service Requirements Manual.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

2. General Provisions for Service

2.1. **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), Temporary Applicants (Section 13), and Doubtful Permanency Customers (Section 14).

2.2. **Schedule of Charges** - An applicant requesting an extension will be provided a sketch showing the Extension Facilities and a quote based on the Schedule of Charges or other applicable details. When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Subdivisions 100 lots or greater or that require feeder, backbone and/or major infrastructure to serve development.

(D) Extension Facilities for General Service applicants that require feeder, backbone and/or major infrastructure or specialized equipment to serve project.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments, Residential Lot Sale, Corporate Business and Industrial Park Developments, or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.



2.3. **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

(C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

(D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

2.4. **Refunds** – The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) The Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High-Rise Development will be five years from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family Developments will be five years and will start three months from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.



SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

2.5. **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6. **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1. Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on an allowance under the following conditions:

(A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site plan has been approved and recorded in the county having jurisdiction.

(C) The total cost of the Extension Facilities (primary, secondary, service), as determined by Company, is less than $10,000 per applicant.

3.2. All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3. Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5. The allowance cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

4. Residential Subdivision Developments

4.1. Extension Facilities will be installed to Residential Subdivision developments of four or more homes in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If the final approved plat is different from

what was originally submitted to the Company, it may cause delays and additional cost for redesign.

4.2. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition or organizational structure of developer.

4.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights.

4.6. The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date the Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7. Examples of the application of Section 4 can be found in Attachment 1 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1. Extension Facilities will be installed to residential "Lot Sale" developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate.

5.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

5.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the

costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan

5.5. Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1. Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2. The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate.

6.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

6.4. Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

7.1. Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost estimate.

7.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition, or organizational structure of applicant.

7.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights etc.

7.6. The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8. General Service Provisions

8.1. Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9. Basic General Service

9.1. Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2. The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3. The cost for Extension Facilities that require feeder, backbone, major infrastructure, or specialized equipment to serve the project, will be determined in accordance with a Project-Specific Cost Estimate.

9.4. Economic Feasibility Analysis for Basic General Service Applicants - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the

project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(E) Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(F) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10. High Rise Developments

10.1. Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:



(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS' Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

10.3. Economic Feasibility Analysis for High Rise Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4. Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

11. Mixed-Use Developments

11.1. Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

11.3. Economic Feasibility Analysis for Mixed Use Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant’s Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4. Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12. Corporate Business & Industrial Park Developments

12.1. Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2. The cost of installing Extension Facilities will be determined in accordance with a Project-Specific Cost Estimate.

12.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

12.4. Company will provide a “Conduit Only Design” provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

12.5. Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.



13. Temporary Applicants

13.1. Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate.

13.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3. When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14. Doubtful Permanency Customers

14.1. When, in the opinion of Company, permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

14.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15. Municipalities and Other Governmental Agencies

15.1. Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2. The effective date for projects enacted under this provision for purposes of Section 2.4 will be the date the municipality or agency provided written approval to the Company to proceed with construction.



SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

16. Change in Applicant's Service Requirements

16.1. Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17. Relocations, Conversions and Upgrades of Company Facilities

17.1. **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2. **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3. **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.



18. Additional Primary Feed or Specialized Equipment

18.1. When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19. Unusual Circumstances

19.1. In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20. Abnormal Loads

20.1. Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21. Master Metering

21.1. **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion is individually metered by Company.

21.2. **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable under the following conditions:

(A) For Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care or;

(B) For Limited-Income Multi-Unit Residential Housing that uses solar power in a "behind-the-meter" application

21.3. **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4. **Conversion from master meter to individually metered system** - Company will convert its facilities from a master metered system to a permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22. Voltage

22.1. All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2. Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.



SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

23. Point of Delivery

23.1. For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

23.2. For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.

23.3. For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

24. Easements

24.1. Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension will be obtained by applicant and provided to Company in Company's name without cost to or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25. Grade Modifications

25.1. If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26. Measurement and Location

26.1. Measurement must be along the proposed route of construction.

26.2. Construction will be on public streets, roadways, highways, or easements acceptable to Company.

26.3. The Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27. Agreements

27.1. **Study and Design Agreements** - Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When

the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.

27.2. **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension; otherwise, the payment will be non-refundable.

27.3. **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28. Applicant Construction of Company Distribution Facilities

28.1. Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2. This option is not available for the following:

(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.

(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3. All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4. Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5. Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6. A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7. For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8. Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29. Settlement of Disputes

29.1. Any dispute between the applicant or prospective applicant and the Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30. Policy Exceptions

30.1. This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission.

(A) The following exceptions have been approved for Rural Municipality applicants:

i. Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by permanent applicants.

ii. The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

iii. The refund eligibility period for Rural Municipal Business Developments will be 7 years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

iv. Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the 7th year refundable period. Any unrefunded advance balance paid at the

start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement.

v. Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

vi. The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

vii. Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

(B) The following exceptions for sections 3, 7, 9, 10, and 11 have been approved for Hopi and Navajo applicants for the extension of electric service to residential and commercial buildings within the Navajo Nation and the Hopi Reservation that are in the APS service territory.

i. APS distribution facilities will be extended up to 2,000 feet at no cost to such applicants.

ii. Applicants requiring distribution facilities extending more than 2,000 feet will pay the amount as calculated through the schedule of charges or project specific costs for any distribution facilities after the initial 2,000 feet from existing APS distribution consistent with the application sections of this schedule.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

SCHEDULE OF CHARGES

Description	Rate	Unit
Single Family Underground	$ 8.40	Per foot
Single Family Overhead	$ 22.40	Per foot
Residential Subdivision*	$ 12.26	Per foot
General Service and Commercial, Single Phase, Underground	$ 16.06	Per foot
General Service and Commercial, Single Phase, Overhead	$ 28.12	Per foot
General Service and Commercial, Three Phase, Underground	$ 42.81	Per foot
General Service and Commercial, Three Phase, Overhead	$ 59.04	Per foot
Single Phase Pole Interset (pole set in existing line)	$ 7,133.39	Each
Three Phase Pole Interset (pole set in existing line)	$ 9,378.39	Each
*Residential Subdivision projects with 100 or more lots will be determined via project specific costs.		

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SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment 1
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

SERVICE SCHEDULE 9

CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

General Description

This Service Schedule provides the terms and conditions under which Arizona Public Service Company (APS or Company) may offer financial incentives to potential new commercial or industrial Customers or to existing commercial and industrial Customers who are adding significant new load.

Availability of this schedule is limited to the lesser of ~~100~~ 125 MW of new and additional load or 50 new Customers with 25 MW reserved specifically for rural projects.

The Customer must provide all requested information to the Company in order to demonstrate eligibility. The Company will evaluate all relevant information and will determine whether to offer the Customer an incentive.

Consistent with the schedule, when the Company determines that it is appropriate to offer an incentive to an eligible Customer, an agreement will be executed with the Customer. The agreement will specify the incentive and other terms where different from the Company's other Service Schedules.

APS will ~~file~~ submit each agreement, along with a complete ~~Customer~~ Characteristics Report with Commission Staff ~~as a compliance filing~~ for review. Each agreement ~~filed~~ submitted with the Commission Staff will become effective after 30 days. ~~after filing.~~

Any Customer information that the Company provides to Commission Staff on a C~~c~~onfidential basis will be returned to the Company ~~no later than~~ within 60 days. ~~after an application under this schedule is filed.~~

1. Eligibility Criteria

The Company will evaluate the following Customer characteristics prior to offering service under this schedule to determine if the Customer is eligible for a financial incentive:

1.1 Availability of Alternative Locations

(A) Incentives are available only to Customers who have not located or expanded in the Company's service area before the Commission's review of the application and who would not locate or expand in the Company's service area without this schedule's incentive.

(B) The Customer must provide the Company with evidence that additional locations, outside the Company's service area, have been considered for location or expansion. This evidence must consist of written documentation including, but not limited to, detailed quantitative analyses performed by the Customer or consultants regarding the suitability of alternative locations.

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SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

(C) Based on the information provided, the Company will determine whether the ~~e~~Customer would reasonably locate elsewhere in the absence of the incentive. If so, the Customer will be deemed to have met this requirement.

1.2 Effects on Competitors

(A) Incentives will be available to the Customer only when existing Customers in the same line of business and market are not adversely impacted by the discounted rates.

(B) The Customer must provide a detailed description of goods and services produced, the technology employed, and the market(s) the C~~c~~ustomer serves.

(C) Based on the provided information, along with knowledge of its customer base, the Company must reasonably verify that this requirement is satisfied for the Customer to be eligible for an incentive.

1.3 Customer Load Requirements

(A) To qualify for this schedule, electric requirements for a new Customer must be at least 2 MW and existing Customers must add at least 1 MW of load (the "New or Expansion Project"). To determine Customer load, APS will consider both energy purchased from the Company and any energy generated by the Customer using cogeneration or small power production facilities.

1. Notwithstanding 1.3(A), new customers locating to an Arizona Rural Municipality must be at least 1 MW to qualify.
2. Arizona Rural Municipality means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

(B) The Customer's monthly average load factor must be 55% or greater. This load factor criterion may be waived if one of the following apply:

1. The Customer's daily off-peak energy usage in kWh is greater than 50% of total monthly energy usage in kWh (off-peak hours will be defined using the applicable general service rate schedule); or
2. The Customer's new or added load is interruptible and the Customer's peak load is at least 3 MW.

(C) Loads that do not operate in the summer months of June through September will be given special consideration when determining an applicable incentive.

(D) APS will assist the Customer to consider and employ state-of-the-art, cost-effective energy conservation and demand response measures at its facility. These measures may include efficiency motors, motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

1.4 Economic Requirements

(A) The load must be economic, as calculated under the Company's current extension policy using standard rates.

(B) To be eligible for incentives under this schedule, a potential load must bring a significant number of jobs or ancillary business into Arizona. In conjunction with this criterion, capital investment by the Cc~~e~~ustomer may also be considered.

(C) The Company will give particular consideration to Cc~~e~~ustomers whose electric bills exceed 5% of their operating expenses.

2. Conflict of Interest

2.1 In order to limit any potential conflict of interest, APS is required to submit an affidavit to Commission Staff for each Customer under consideration for service under this Service Schedule. This affidavit will include:

(A) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries, or one who has filled such role within the three-years prior to the effective date of the Customer's agreement, to the Company's knowledge, has or had any material interest, direct or indirect, in any substantial services, including real estate broker services, provided to the Customer in connection with the New or Expansion Project; and

(B) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has, or within the prior 12 months had, any direct or indirect material interest in any real property owned in whole or in part by the Customer in connection with the New or Expansion Project.

2.2 If the affidavit provided by APS is shown to be inaccurate, the Commission will, in future APS rate cases, impute as revenue the difference between the discounted rate and the tariffed rate which would otherwise apply to the Cc~~e~~ustomer for the period during which the discount was in effect.

2.3 To the extent APS cannot obtain the requested affidavit, APS may submit an affidavit to Commission Staff disclosing the nature of any such known material interests and explain why an affidavit cannot be obtained.

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

3. Rate Provisions

3.1 A Customer satisfying the requirements above may receive an incentive to locate in the Company's service territory. The incentive will be a discount from the Customer's otherwise applicable base electric bill (excluding taxes and adjustments).

3.2 The discounted charges will not be below the Company's marginal cost.

3.3 The discount may vary over the term of the Customer agreement.

3.4 The discount will not be larger than 25% of the Customer's total energy bill from the Company.

3.5 No discount will be provided from the minimum bill as computed under the Customer's otherwise applicable rate.

3.6 For current customers adding load, the discount will apply only to the added load.

3.7 Any incentive available under this schedule will be limited to a specific period of six years or less.

3.8 The specific discount and the period over which the discount is applied will be determined after full evaluation of the Customer information as determined by the Company.

4. ~~Customer~~ Characteristics Report

Each agreement must be accompanied by a Customer provided Characteristics Report. The following information will be included in the ~~Customer~~ Characteristics Report provided by the Customer unless otherwise noted:

4.1 General Information
- (A) Customer name
- (B) Customer contact—name and address
- (C) Dates of C~~c~~ustomer application and Company decision
- (D) New or existing C~~c~~ustomer
- (E) Proposed effective date of agreement
- (F) The number of direct permanent full-time jobs being created in APS service territory
- (G) The average percent of County Median Wage for the direct jobs being created
- (H) The anticipated capital investment to be made by the Customer

4.2 Location Decision
- (A) Customer location
- (B) Description of other locations considered
- (C) Other locations of C~~c~~ustomer's operations

aps

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

(D) An affidavit from ~~e~~Customer demonstrating that the C~~c~~ustomer would not locate or expand in Arizona absent the discounts
(E) Within ninety (90) days of the effective date of any agreement under this Schedule, the C~~c~~ustomer must supply written documentation and analyses substantiating the affidavit provided under 4.2 (D)
(F) If the requirements of 4.2 (E) are not met within ninety (90) days of approval of the agreement, the agreement will be void
(G) Proportion of C~~c~~ustomer's production and distribution expenses accounted for by electricity, by natural gas, and by other energy sources (specify)

4.3 Effects on Competitors
(A) Description of the ~~Nature of~~ business ~~– description and North American Industry Classification System (NAICS) code~~
(B) Number of other C~~c~~ustomers in same business
(C) Market area served by C~~c~~ustomer
(D) Description of effects on other C~~c~~ustomers in Arizona

4.4 Load Characteristics
(A) Size of load
(B) Annual load factor
(C) Off-peak operation
(D) Description of daily load shape
(E) Seasonality
(F) Interruptibility
(G) Permanency of load
(H) Estimated impact on system peak demand from the new load

4.5 Energy Service Mix
(A) Use of natural gas and other energy sources
(B) Description of energy efficiency measures—building design, processing, and other
(C) Feasibility of cogeneration

4.6 Rates – APS Provided
(A) Applicable rate schedule
(B) Years discount will be in effect
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(E) Estimated annual incremental electricity production costs
(F) Support that the agreement meets the terms described in Rate Provisions 3.2 and 3.4

4.7 Special Agreement Provisions – APS Provided
(A) List of special provisions
(B) Reasons for special provisions

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SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

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SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

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(C) Other locations of Customer's operations

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

(D) An affidavit from Customer demonstrating that the Customer would not locate or expand in Arizona absent the discounts
(E) Within ninety (90) days of the effective date of any agreement under this Schedule, the Customer must supply written documentation and analyses substantiating the affidavit provided under 4.2 (D)
(F) If the requirements of 4.2 (E) are not met within ninety (90) days of approval of the agreement, the agreement will be void
(G) Proportion of Customer's production and distribution expenses accounted for by electricity, by natural gas, and by other energy sources (specify)

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(A) Description of the business
(B) Number of other Customers in same business
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(H) Estimated impact on system peak demand from the new load

4.5 Energy Service Mix
(A) Use of natural gas and other energy sources
(B) Description of energy efficiency measures—building design, processing, and other
(C) Feasibility of cogeneration

4.6 Rates – APS Provided
(A) Applicable rate schedule
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(F) Support that the agreement meets the terms described in Rate Provisions 3.2 and 3.4

4.7 Special Agreement Provisions – APS Provided
(A) List of special provisions
(B) Reasons for special provisions

Description of Compliance and Reporting Requirements Proposed to be Eliminated

Line No.	Decision No.	Docket	Topic	Frequency	Description	Justification
1	76295 Pg. 110, Line 21 – Pg. 111 Line 6 (8/18/2017)	E-01345A-16-0036 / E-01345A-16-0123	E-32L Storage Pilot (SP)	Non-Dated	Evaluate cost/benefit of program and conduct stakeholder meetings when 70% of program capacity is reached to determine new program parameters; file either new program or, if stakeholders cannot agree, file request for Commission to establish program parameters.	Rate Schedule E-32L SP as approved in Decision No. 76295 has been superseded by the E-32L SP approved in Decision No. 78317. This compliance requirement is no longer necessary.
2	68112 Attachment A Pg. 9, Para. 39 (9/9/2005)	E-01345A-03-0775 / E-01345A-04-0657	Bill Estimation	Every 3 Years	Conduct an audit of estimation, meter reading, and billing practices.	Four consecutive audits have shown that APS's bill estimation, meter reading, and billing practices are robust and function as intended. These audits are no longer necessary.
3	76295 Pg. 111-112 (8/18/2017)	E-01345A-16-0036 / E-01345A-16-0123	E-32L Storage Pilot	Annual	Report customer participation in the E-32L SP Program.	Rate Schedule E-32L SP as approved in Decision No. 76295 has been superseded by the E-32L SP program approved in Decision No. 78317. This compliance requirement is no longer necessary.
4	68741 Exhibit A Pg. 8, Para. VIII (6/5/2006)	E-00000A-01-0630 / E-00000A-02-0051	Electric Competition	Annual	Report to the Commission on APS's retail competition activities and transactions with Retail Competitive Affiliates as part of the ACC Code of Conduct.	Retail competition in the state of Arizona is no longer in force, therefore APS and its affiliates conduct no competition activities and the reason this report was required no longer exists. This filing requirement is outdated and unnecessary. This request applies to the annual reporting requirement only.
5	77270 Pg. 10, line 9 (6/27/19)	E-01345A-19-0003	Gross Margins Report	Quarterly	Report gross margins associated with variances in revenue between the 2016 rate case billing assumptions and 2018 actuals.	Decision No. 78317 changed residential rate designs from those employed in the 2016 Rate Case. This calculation is outdated and no longer reflects APS's billing assumptions or revenue from rates.
6	76295 Exhibit A Pg. 18, Para. 17 (8/18/2017)	E-01345A-16-0036 / E-01345A-16-0123	R-Tech Pilot	Monthly	Convene stakeholders when the R-Tech Pilot reaches 6,000 participants and report to the Commission once the R-Tech Rate Schedule reaches 7,000 customers.	The R-Tech Rate Schedule as referenced in this compliance requirement has been superseded by the R-Tech Rate Schedule approved in Decision No. 78317. This compliance requirement is no longer necessary.

DIRECT TESTIMONY OF JAMIE R. MOE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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DIRECT TESTIMONY OF JAMIE R. MOE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Jamie R. Moe. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am the Manager of Regulatory Affairs for Arizona Public Service Company (APS or Company). I have management responsibility for all aspects relating to rate strategy and specific rates and prices.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have over 19 years of experience in the utility industry. From 2003 to 2006, I served as a Staff Analyst with the Arizona Corporation Commission (ACC or Commission). From 2007 to 2009, I worked for Global Water Resources as a Regulatory Analyst, and from 2015 to 2017, I worked for Arizona Water Company as Manager of Rates and Regulation. I originally joined APS in 2010 as a Senior Rate and Regulatory Analyst and returned in 2017 as Rate Strategy Consultant and later as Rate Strategy Advisor. I now manage the Company's Rate Design and Revenue Requirements teams, which are responsible for analyzing and aligning costs with appropriate pricing structures. I have a Bachelor of Science degree in Accounting from North Dakota State University.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. Yes. I have testified at the Commission for ACC Staff and Global Water Resources, Inc.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My Direct Testimony supports APS's application regarding the following:

- Standard Filing Requirement Schedules (SFRs) A-1, portions of A-2, B-1, B-2, B-3, B-4a, C-1, C-2, F-1 SFR Schedules, and all G SFR Schedules;
- APS's Cost of Service Studies (COSS);
- Proposed changes to the Cost of Service (COS) for residential solar customers, as well as the differences in cost allocation using site load and delivered load; and
- Fair Value Increment (FVI) and Fair Value Rate of Return (FVROR).

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My Direct Testimony addresses certain SFR schedules including SFR Schedule A-1, which calculates the increase in APS's base rate revenue requirements of $772.3 million. I discuss the steps required to implement the rate adjustment mechanism proposal that is more fully described by APS witnesses Jessica Hobbick and Theodore Geisler, which includes the elimination of the Lost Fixed Cost Recovery (LFCR) and the Environmental Improvement Surcharge (EIS) adjustment mechanisms. The base rate revenue increase includes APS's proposal to transfer $107.83 million in collections from adjustment mechanisms into base rates, a concurrent change to the PSA rate reduction of $220.59 million, and a concurrent REAC revenue increase of $ 16.09 million. These adjustor transfers do not change the total amount collected from customers but rather would move the following revenues into base rates:

1. A portion of the energy efficiency expense currently collected in the Demand Side Management Adjustment Charge (DSMAC), in the amount of $39.0 million (ACC jurisdiction less revenue credits);

2. A portion of the lost fixed costs currently collected through the LFCR mechanism, in the amount of $58.5 million (ACC jurisdiction); and
3. The revenue requirement for environmental compliance currently collected in the EIS, in the amount of $10.3 million (ACC jurisdiction less revenue credits).

The following Day-One[1] changes to adjustors will also occur outside of costs transferred to base rates and have additional impact to the net impact on customer bills:

1. A portion of the deferred fuel-related revenues currently collected in the Power Supply Adjustor (PSA), in the amount of $220.6 million (ACC jurisdiction), will be reflected in a lower PSA rate; and
2. The revenue requirement for the Renewable Energy Adjustment Charge (REAC) will increase by the amount of $16.1 million related to Coal Community Transition (CCT) (ACC jurisdiction);

Figure 1 below shows the components of the Company's proposed base rate increase, inclusive of adjustor transfers and deferred Test Year fuel costs.

[1] Day One changes refer to changes in adjustor rates that will occur the same day that new base rates are implemented in this rate case.

Figure 1. Total Net Bill Impact[2]

Net Impact = Net Base Rate Increase + Net Adjustor Changes	**Dollars**	**Bill Impact**
Base Rate Increase		
Total Revenue Deficiency	$772.27M	22.87%
Adjustor Transfers	($107.83M)	(3.19%)
Base Rate Increase Net of Adjustors	$664.44M	19.68%
Day-One Power Supply Adjustment (PSA) Revenue Reduction	($220.59M)	(6.53%)
Day-One Renewable Energy Adjustment Charge (REAC) CCT Revenue Increase	$16.09M	**0.48%**
Day-One Net Rate Impact	**$459.94M**	**13.62%**

If APS's proposed rates are adopted as requested by the Company, customers will experience a net base rate increase of $459.9 million—an overall average bill increase of 13.6%. The net increase and bill impact to customers is further discussed in the testimonies of Mr. Geisler and Ms. Hobbick. This additional revenue will provide APS an opportunity, not a guarantee, of earning a FVROR of 4.92% on a Fair Value Rate Base (FVRB) of $16.6 billion.

My Direct Testimony also describes the COSS used to support APS's rate design as well as the jurisdictional allocation of costs. In addition, I sponsor the additional COSS required by Decision No. 78317 (November 9, 2021).

Finally, my Direct Testimony explains the calculation used to determine the FVI derived from the Company's FVRB. The mechanics of the calculation are based on those adopted by the Commission in numerous decisions, including Decision

[2] Numbers in the figure have been rounded for ease of presentation.

Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), 76295 (August 18, 2017), and 78317.

III. PROPOSED BASE FUEL AND PURCHASED POWER RATE

Q. IS APS PROPOSING ANY CHANGES TO TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. Yes. I am sponsoring a pro forma that removes any deferrals of fuel expense included in the Test Year due to the operation of the PSA. This pro forma also removes the non-cash mark-to-market impacts. These non-cash accounting adjustments have no impact on the Company's actual Test Year fuel expense or anticipated future fuel expenses. These two adjustments result in an increase to Test Year expenses of $212.3 million and are shown in the Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals pro forma in SFR Schedule C-2, page 2, column 7.

Q. WHAT IS APS'S PROPOSAL FOR ITS BASE FUEL AND PURCHASED POWER RATE IN THIS PROCEEDING?

A. APS proposes to adjust its base fuel rate to better reflect its expected fuel and purchased power costs in the future. The Company's proposal increases the current base fuel and purchased power rate of 3.1451 ¢/kWh (as authorized by the Commission in Decision No. 78317) to 3.8321 ¢/kWh, an increase of 0.6870 ¢/kWh, with an equal and concurrent offset in PSA revenues at the time rates determined in this proceeding go into effect. APS witness Justin Joiner discusses APS fuel cost management efforts and fuel operations.

Q. HOW DID APS DETERMINE THE PROPOSED RATE?

A. The proposed fuel rate was determined by using the Test Year fuel rate as a baseline and using the 2023 fuel forecast discounted by 4% to remain near that Test Year baseline to minimize additional bill impact to customers. The 2023 forecasted fuel

cost includes the removal of $15 million off-system sales mitigation for AG-X, which is described by Ms. Hobbick.

Q. HOW DOES THIS NEW BASE FUEL RATE AFFECT TEST YEAR EXPENSE?

A. Because the Test Year cost of fuel and purchased power expense actually incurred results in a Test Year fuel rate of 3.8281 ¢/kWh, the Base Fuel and Purchased Power Cost pro forma reflects an impact to Test Year operations of $1.2 million resulting in the proposed base fuel rate of 3.8321 ¢/kWh. The Base Fuel and Purchased Power pro forma calculations are provided in SFR Schedule C-2, page 2, column 6. Ms. Hobbick further describes the impact of APS's proposal to offset the increase in the base fuel and purchased power rate with a concurrent reduction in recovery through the PSA.

Q. WHAT CHANGE IN THE BASE RATES FOR PRODUCTION-RELATED CHEMICAL COSTS AND SALES OF EMISSIONS ALLOWANCES IS APS PROPOSING?

A. APS proposes that the current base production-related chemical cost of 0.05 ¢/kWh, authorized in Decision No. 78317, be increased to 0.0744 ¢/kWh. This rate reflects the $21.3 million actual cost of chemicals during the Test Year. The amount and costs of lime, ammonia, and sulfur associated with power plant emission controls varies with the amount of fuel burned at generating plants, and these costs were authorized for recovery through the PSA by the Commission in Decision No. 76295. Costs of these chemicals increased for many of the same reasons as fuel and purchased power prices are increasing, including inflationary impacts, raw material shortages, and supply chain issues, which are slowing the production of these chemicals. In addition, freight and other transportation costs have also increased. This proposal will increase the base cost of chemicals by approximately $7.1 million, with an equal and concurrent decrease in PSA

revenues at the time rates determined in this proceeding go into effect. The impact of this adjustment is shown in the Chemical O&M pro forma in SFR Schedule C-2, page 3, column 8.

APS does not propose to change the current PSA base rate of ($0.000001) ¢/kWh for net margins from emission allowance sales.

IV. STANDARD FILING REQUIREMENT SCHEDULES (SFRS)

Q. PLEASE IDENTIFY THE SFRS THAT YOU ARE SPONSORING.

A. I am sponsoring SFR Schedule A-1, portions of SFR Schedules A-2, B-1, B-2, B-3, B-4a, C-1, C-2, F-1, and all G SFR Schedules.

The schedules themselves also contain numerous adjustments sponsored by other APS witnesses. I have attached an SFR index that lists the APS witnesses responsible for preparation of the various SFRs or elements of the SFRs (Attachment JRM-01DR).

Q. PLEASE DESCRIBE THE PORTIONS OF THE SFRS THAT YOU ARE SPONSORING.

A. SFR Schedule A-1 presents the requested overall increase in retail revenue requirements. SFR Schedule A-1 demonstrates that the adjusted Test Year rate of return for ACC jurisdictional operations was 1.43% on a FVRB of $16.6 billion. The rate of return on FVRB resulting from the requested increase of $772.3 million is 4.92%.

The Company's FVRB is a calculation based on the average of the Original Cost Rate Base (OCRB) and the Reconstruction Cost New less Depreciation (RCND) rate base. This calculation has been accepted historically by the Commission as an appropriate way of determining the FVRB. I show the FVRB in Attachment JRM-

07DR, which also offers a detailed calculation of the FVI discussed later in my testimony.

I sponsor portions of SFR Schedules B-1 and B-2, which provide the calculations of rate base for Total Company and ACC jurisdictional operations. The jurisdictional operations rate base calculations were developed through a COSS. I also sponsor the jurisdictional allocation portion of SFR Schedule B-4a, which shows the computation of adjusted jurisdictional RCND rate base as of June 30, 2022, using the same allocation factors as with OCRB.

Additionally, I sponsor portions of the C SFR Schedules that present the pro forma adjustments to the Test Year and the jurisdictional splits of the pro forma adjustments between Total Company and ACC jurisdictional operations. The sponsorship of the individual pro forma adjustments is noted on SFR Schedule C-2.

The G SFR Schedules provide detailed information regarding the Company's COSS. These schedules address existing and expected percentages of COS and rates of return by sub-class, show pro forma adjusted amounts of OCRB and operating expenses allocated to ACC jurisdictional customers, and list the allocation factors used in preparing the study.

- SFR Schedule G-1 shows percentages of the COS and the original cost rate of return at existing rates by customer class, based on the adjusted Test Year COSS.
- SFR Schedule G-2 is similar to SFR Schedule G-1, except it reflects percentages of the COS and returns by customer class that would result under APS's proposed rates.

- SFR Schedule G-3 shows the functionalized dollar amount and percentage of adjusted rate base allocated to each retail customer class.
- SFR Schedule G-4 shows the functionalized amount of operating expenses allocated to each retail customer class.
- SFR Schedule G-5 shows the amount of functionalized adjusted rate base allocated to ACC jurisdictional customers.
- SFR Schedule G-6 shows the amount of functionalized adjusted operating expenses allocated to ACC jurisdictional customers.
- SFR Schedule G-7 lists the allocation factors used in preparing the Test Year COSS.

Q. DO YOU SPONSOR ANY OTHER DOCUMENTS RELATED TO CLASS COST OF SERVICE?

A. Yes. Attachments JRM-02DR (site load COSS residential broken out), JRM-03DR (site load residential combined) and JRM-04DR (delivered load COSS residential broken out) to my testimony are summaries showing:

1. The jurisdictional separation of rate base costs, revenues, and operating expenses between ACC and all other jurisdictions;
2. The further allocation by retail customer class of total ACC allocated costs and the percentage of cost to serve paid by each major customer class;
3. The same information as described in (2) above for each general service sub-class; and,
4. The same information as described in (2) above for each residential service sub-class, including the solar energy and demand rate sub-classes where applicable.

V. COST OF SERVICE STUDY (COSS)

Q. PLEASE DESCRIBE A COSS GENERALLY.

A. A COSS is a detailed assessment of utility costs and revenues that supports a requested rate increase, both in total and for separate rate classes. The study compiles and evaluates the utility's costs for the Test Year period and makes certain normalizing pro forma adjustments to reflect an appropriate test of the adequacy of the utility's rates. The COSS separates the cost and revenue information to reflect those that are jurisdictional to the Commission. Lastly, the study allocates the costs and revenues to various customer rate classes based on cost drivers or cost causation principles. This allocation sets the cost responsibility and revenue deficiency for each class.

Q. WHAT IS THE TEST YEAR FOR APS'S COSS IN THIS RATE CASE?

A. APS conducted an embedded COSS using data from the 12-month period ending June 30, 2022, as the test period. An embedded COSS takes the total revenue requirement and allocates it among customer classes.

Q. PLEASE DISCUSS THE DEVELOPMENT OF THE COSS.

A. This study was prepared using accepted methods of functionalization, classification, and allocation.

Q. WHAT IS FUNCTIONALIZATION?

A. **Functionalization** is the process of attributing each rate base or expense item to a particular function—namely production (generation of electricity), transmission, distribution, or customer service (*e.g.*, metering and billing)—in the provision of electric service. An example of functionalization is assigning the costs of building and operating the Company's generation power plants to the production function.

Q. WHAT IS CLASSIFICATION?

A. **Classification** is the process of determining the factor or factors that drive the magnitude of the cost. For example:

- If a cost to serve is driven by the amount of kWh energy consumed, such as fuel cost, it is classified as energy.
- If a cost is driven by the rate at which energy is consumed, or kW capacity, it is classified as demand.
- If a cost is driven by the number of customers taking service on the APS system, irrespective of either the kW demand or kWh energy, it is classified as customer.

Q. WHAT IS ALLOCATION?

A. **Allocation** occurs after a cost has been functionalized and classified. Allocation factors—such as class coincident peak (CP) demand contribution at the time of system peak, non-coincident class peak (NCP), the sum of individual peaks, energy, or number of customers—are applied to allocate costs to other jurisdictions, customer classes and sub-classes, and rate schedules. A simple example is the allocation of energy-related costs by kWh consumption to different customer classes.

In summary, in the COSS, the total expense and rate base items that comprise APS's costs are grouped into major categories, such as Plant in Service or Operating and Maintenance (O&M) expense. Each category is first functionalized into production, transmission, distribution, or customer-related costs, then classified as demand, energy, or customer-related. Allocation factors based on kW, kWh, and number of customers are then developed so that the functionalized and classified costs may be allocated to the ACC retail jurisdiction and to the various retail customer classes and sub-classes.

Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated between jurisdictions based on the average of the system peak demands occurring in the months of June, July, August, and September (collectively referred to as 4-CP, with the months being core summer months) to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its rate cases before the Federal Energy Regulatory Commission (FERC) and creates jurisdictional alignment to ensure the right proportion of cost is being allocated to each jurisdiction. It also eliminates the potential that costs are not recovered from either jurisdiction due to differences in allocation methods. It has been accepted as the jurisdictional allocation methodology by the Commission for many years.

Within the ACC jurisdictional customer classes, production costs were allocated based on the Average and Peak Demand (A&P) method. This method was adopted by the Commission in Decision No. 78317. The A&P method uses the sum of an energy, or average demand, allocator as well as a peak demand allocator:

1. **Energy (Average Demand) allocator** – each class's Test Year energy usage divided by 8,760 hours to calculate average energy demand.
2. **Peak Demand allocator** – the average of the customers' 4-CP during the months of June, July, August, and September.

In addition, APS analyzed the AG-X customer group as a separate customer class in the allocating of generation-related costs.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the COSS. However, a portion of transmission costs are brought back into the ACC jurisdictional cost of service to offset the existing Open Access Transmission Tariff (OATT) revenues from jurisdictional customers. Such an offset ensures that there is no double-counting of transmission costs between the ACC and non-ACC jurisdictions, and effectively assumes that each customer class pays the cost of transmission service.[3]

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not coincide with the system peak load. Thus, costs related to distribution substations and primary distribution lines are typically allocated based on NCP loads. However, a portion of these costs are allocated on a customer basis.[4] Allocation of costs related to distribution transformers and secondary distribution lines are based on the summation of the individual peak loads or demands of all customers within a particular customer class (Sum of Individual Max). Each of these allocation methods has been used by APS and accepted by the Commission for many years.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COSS.

A. APS sells electric service to parties that are not traditional APS retail customers, such as sales to rate schedule E-36 XL customers for station service power to large generation plants owned by others. These transactions produce net benefits because their rates more than cover their incremental costs. Therefore, these revenues are allocated, or credited, to all customer classes. In other words, the entire margin that

[3] The one exception for transmission costs is residential rooftop solar customers. To address the mismatch between what solar and non-solar residential customers pay for the transmission portion of their bills, APS reallocated the direct assigned cost responsibility to residential customers using each residential sub-class's 4-CP.

[4] *See* Decision No. 78317 at 241, lines 2-6.

APS realizes from these non-retail transactions is attributed to each class through the revenue credit, benefiting all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm, short-term transactions, and other small items, such as rent from electric property, forfeited discounts, miscellaneous service revenues, and other electric revenues, as revenue credits.

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES DEVELOPED BY THE COSS?

A. The COSS only addresses the base rate portion of the cost to serve. Additional revenues and expenses from adjustors are removed from the COSS to get a base rate revenue requirement. Various adjustors, surcharges, regulatory assessments, sales/transaction privilege taxes, and franchise fees are charged outside of base rates.

Q. DID YOU REVISE APS'S COSS METHODOLOGY TO COMPLY WITH THE MOST RECENT RATE CASE DECISION?

A. Yes. APS made the following changes to its cost allocation process as required in Decision No. 78317:

- The production demand costs (power plants) were allocated using the Average and Peak (A&P) method specified by the Commission.[5]
- The primary distribution costs in FERC Accounts 360, 361, and 364 through 368 were allocated as both demand-related and customer-related with relevant allocators.[6]

[5] *Id.* at 234.
[6] *Id.* at 241.

- Three separate COS studies were performed for residential solar classes: one using site load, another using delivered load, and a third combining solar customers with non-solar customers within their general rate class.[7]

In these three studies, the allocation of primary distribution costs for solar and non-solar classes used the load coincident with the time of the total residential NCP (combining both solar and non-solar customers).[8]

Also in these three studies, the meter costs included the actual bi-directional meter cost from the end of the Test Year but excluded the cost of separate production meters.[9]

VI. ALLOCATION OF PRODUCTION CAPACITY COSTS

Q. WHAT IS THE DIFFERENCE BETWEEN THE AVERAGE AND EXCESS DEMAND (A&E) AND A&P ALLOCATION METHODS?

A. The A&P method calculates two components: (1) each class's share of annual energy (or average demand) and (2) each class's share of peak demand. These two components are then combined with a simple average or some type of weighted average calculation. The A&E method also calculates two components: (1) each class's share of average demand and (2) each class's share of the peak demand component that exceeds average demand. It is the formulation of the second component that separates the two methods.

[7] *Id.* at 255, lines 19-23.
[8] *Id.* at 255, lines 27-28.
[9] *Id.* at 255, lines 24-26.

Q. WHAT DID THE COMMISSION CONCLUDE IN DECISION NO. 78317 CONCERNING THE COST DRIVER FOR APS'S PRODUCTION DEMAND COSTS?

A. The Commission concluded that "APS is a summer-peaking utility, and a large portion of its production costs are attributable to peak demand. Accordingly, an equitable method of allocating production costs will recognize causation of the peak demand."[10]

Q. DOES THE ADOPTED A&P METHOD ATTRIBUTE A "LARGE PORTION" OF PRODUCTION COSTS TO PEAK DEMAND?

A. No, it does not. In fact, it allocates fewer of such costs to system peaks than either 4-CP or A&E.

Q. PLEASE EXPLAIN.

A. The A&P method attributes a large portion of production demand costs to annual energy usage and only a smaller, secondary portion to summer peak demand. In other words, the A&P method rests on the assumption that a large portion of power plant capacity costs are driven by customers' energy usage, 24 hours a day, 7 days a week, in both summer and winter seasons. This is just not the case, especially for APS's service territory.

In addition, the A&P method makes matters worse by double weighting the energy component. This occurs because the A&P method combines an annual energy component, which is the same thing as average demand, with a peak demand component. The double weighting of energy occurs because the second component (i.e., the peak demand) includes each class's share of the entire peak demand (i.e., both the average demand portion and the remaining amount). In short, the average

[10] *Id.* at 234, lines 12-14.

demand component is factored into both the energy and peak portions of the allocator, and thus counted twice.

Q. DOES THE A&E METHOD HAVE THE ISSUE OF DOUBLE WEIGHTING THE ENERGY COMPONENT?

A. No. The A&E method uses (1) average demand (energy) and (2) the portion of peak demand that is above or more than the average demand, and not the entire peak, as is used in the A&P method. Because the second component of the A&E method only uses each class's contribution to excess peak demand, it does not suffer from the same double counting flaw as the A&P method.

Q. DOES THE SPECIFIC A&P METHOD REQUIRED BY THE COMMISSION FURTHER OVEREMPHASIZE THE ENERGY COMPONENT?

A. Yes. The A&P method adopted by the Commission further compounds the flaw in the model by using a particular weighted average calculation to combine the energy and peak components, which places even more emphasis on the energy component. This method not only doubles the energy component of the allocator, but then places additional weight on the energy component when the two components (energy and peak) are combined.

Q. DOES APS SUPPORT USING THE A&P METHOD TO ALLOCATE PRODUCTION COSTS AS WAS ORDERED IN APS'S LAST RATE CASE DECISION?

A. No. As discussed above, the A&P method places too high of an emphasis on annual energy as a cost driver for production capacity, as opposed to summer peak demand. As long as summer peak demand is a key driver for production capacity costs in Arizona, the A&P method is not the best way to reflect this cost driver.

Q. HOW DO OTHER JURISDICTIONS ALLOCATE PRODUCTION DEMAND COSTS?

A. Generally, I am aware that many utilities use the 4-CP method or a similar method to allocate production demand costs because it recognizes that the primary driver for these costs is the system peak demand.

In addition, if an allocator is used that combines both peak demand and energy, the A&E method is preferred by most jurisdictions given the double counting flaw in the A&P method discussed above. The A&P method is rarely adopted in other jurisdictions for electric utilities.

Q. WHAT DOES APS RECOMMEND CONCERNING THE ALLOCATION METHOD FOR PRODUCTION CAPACITY COSTS?

A. APS requests, given the issues discussed previously and highlighted below, that the Commission re-examine its preferred method to allocate production demand costs and adopt the A&E and/or 4-CP methods rather than the A&P method.

- The 4-CP method is more consistent with the recognition that a large portion of production demand costs are caused by the summer peak. It allocates these costs based on each class's load, coincident with the system peak, in June, July, August, and September.
- The A&E method accurately reflects the costs for the residential class because the CP and NCP information used in this method is very consistent.
- The traditional A&E method will likely overstate the costs for classes with low load factors where the NCP differs materially from the CP, such as schools and churches. However, these are relatively small sub-classes of the general service class and this deficiency in the A&E method for these sub-classes could be resolved by using 4-CP in place of NCP.

VII. SOLAR COST OF SERVICE STUDY

Q. WHAT IS THE PURPOSE OF A SOLAR COSS?

A. The adoption of residential rooftop solar systems has grown significantly over the last ten years. In addition, these systems are designed to last 20 years or more. This class of customers is substantial and growing. These customers have unique energy usage and on-site generation, with related impacts on the cost to serve them and important ramifications for recovery of their cost of service in rates.

The Commission held hearings on the Cost and Value of Solar (CVS) to explore and address these issues. One key question was whether residential solar customers were paying a fair share of their cost of service in rates, or whether these costs were being under-recovered shifting recovery to non-solar customers.

The Commission, among other things, ultimately determined that residential customers with solar were partial requirements customers and the question of whether solar customers are paying their fair share of their cost of service would be best answered in a solar COSS in a rate case. Thus, the purpose of the solar COSS is to determine whether solar customers are paying rates that appropriately cover their costs.

Q. DID APS PERFORM A SOLAR COST OF SERVICE STUDY IN THIS CASE?

A. Yes. As ordered by the Commission in Decision No. 78317, APS performed a COSS for the residential solar class using two approaches—a top-down approach and a bottom-up approach. In the last two rate cases, APS presented the solar COSS using only the top-down approach.

Q. PLEASE EXPLAIN THESE APPROACHES.

A. Both approaches compare the utility costs incurred for the solar class with the actual revenues collected. If the annual revenues from rates are less than the costs incurred, then the solar class is underpaying for its cost of service, and vice-versa.

The first approach, the top-down approach, calculates the cost of service for the site load and then evaluates cost credits for the self-supply.[11] This allocates grid and power plant costs according to the total consumption in the home—not just the load metered by the utility. Next, the savings in the utility's grid and power plant costs that occur because of the solar generation self-supply are estimated and credited back against the site load cost of service. Finally, the net value of the solar generation that is exported to the grid is calculated by comparing the fuel cost savings that the utility incurs to the price the utility pays for this power, either through the net metering program or the Resource Comparison Proxy (RCP) program. The top-down approach calculates the net impact on utility costs from a solar customer, which is the cost responsibility that should be recovered in rates.

The second approach, the bottom-up approach, calculates the cost of service based on the delivered load (i.e., the load supplied by the utility) and then adds additional utility costs that are being incurred on behalf of the solar customer, based on the self-supply load information. These additional costs include such things as standby and back-up capacity costs for power plants and the grid, upon which the solar customer continues to rely, and secondary service costs that are not eliminated or reduced when a customer adds solar generation to its home. This approach also calculates the net value (or cost) of the solar export power.

[11] Part of the solar generation in any instant directly serves the load in the home, which is referred to as "self-supply" and the remaining excess portion is exported to the grid.

Q. WHY NOT BASE THE COSS SOLELY ON THE DELIVERED LOAD, LIKE OTHER CUSTOMER CLASSES?

A. Because doing so would significantly understate the costs that the utility incurs to serve the solar customer. As discussed above, the solar customer has partial requirements service where only a portion of their load is generally served by the utility and a portion by the on-site generator or self-supply. Both portions require support and costs from the utility because the customer is still hooked up to the grid and relies on the utility to back-up their solar generator and to provide the service needed for the home. A COSS based solely on the delivered load portion would ignore the costs for the self-supply portion.

VIII. SOLAR COSS – TOP-DOWN APPROACH (SITE LOAD)

Q. PLEASE DESCRIBE THE TOP-DOWN APPROACH TO SOLAR COSS.

A. As mentioned above, the top-down approach to a solar COSS first evaluates the cost of service based on the site load, which is the total consumption in the home, and then credits back the utility cost savings from the solar generation. APS used this approach in each of its last two rate cases. A summary review of the top-down approach and corresponding results are discussed below.

Q. HOW WERE THE SITE LOAD COSTS DETERMINED?

A. The hourly site load for the Test Year was developed by adding the hourly delivered load and the portion of the hourly solar generation that was used for self-supply. The resulting site load reflects the total consumption in the home. The cost of utility service was then determined for the site load based on the standard cost-of-service allocation methods used for the other customer classes, as described above.

Q. HOW WERE THE SOLAR CREDITS DERIVED?

A. The utility cost of service savings from the solar generation, which were credited against the site load cost of service, were derived by computing the percentage

difference between the relevant credit factor for the site load versus the delivered load. This percentage difference was then applied to the site load gross revenue requirement. The credit factors for each cost type are as follows:

- Production Demand Credit – based on 4-CP and summer average NCP
- Transmission Credit – based on 4-CP
- Distribution Substation Credit – based on summer average NCP
- Distribution Primary Credit – based on summer average NCP
- Distribution Secondary Credit – based on average sum of individual max peaks for the summer months

Q. HOW WAS THE NET VALUE OF THE SOLAR EXPORT POWER DETERMINED?

A. The solar export power reduces the overall cost of fuel for the utility, which was valued at the new base fuel cost proposed in this rate case. This fuel cost reduction was then netted against the price paid to the solar customers for this export energy, either through the net metering or RCP programs.

Q. WHAT WERE THE RESULTS OF THE TOP-DOWN SOLAR COSS?

A. The results of the top-down solar COSS are provided in Attachment JRM-05DR and a summary of the results are shown in Figure 2.

Figure 2. Solar Cost of Service

(Top-Down Approach)

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
% COS Recovered	**37.7%**	**68.0%**	**50.4%**	**56.2%**

IX. SOLAR COSS – BOTTOM-UP APPROACH (DELIVERED LOAD)

Q. PLEASE DESCRIBE THE BOTTOM-UP APPROACH TO SOLAR COSS.

A. As discussed above, the bottom-up approach calculates the COSS based on the delivered load for the solar class and then assesses the additional costs for services upon which solar customers continue to rely on, and for which the utility incurs costs, in addition to the costs associated with the delivered load. The net value of the export power is also assessed. As a first step, the cost allocation for delivered load for the solar class follows the general retail allocation process described above.

Q. WHAT ARE THE ADDITIONAL COSTS TO SERVE SOLAR CUSTOMERS NOT REFELCTED BY DELIVERED LOAD?

A. The additional costs to serve solar customers, beyond those captured in the delivered load, include:

- The back-up costs for production capacity needed to "firm up" the solar generation to provide reliable service to the solar customer at issue;
- The reserve margin for generation;
- The generation services that the solar customer relies upon, but which cannot be supplied from solar generation. These services would include items such as ramping, integration costs, and in-rush current supply;
- The primary grid costs that the solar customer continues to rely on and benefit from as they remain connected to the grid;

- The primary grid costs that are used by the solar customer to export power to the grid; and
- The secondary grid costs that are sized to serve the connected load of the house and are not reduced when the customer adds solar generation.

Q. PLEASE EXPLAIN THE BACK-UP PRODUCTION CAPACITY COSTS FOR SOLAR CUSTOMERS.

A. One of the key findings of the CVS hearing was that rooftop solar customers are partial requirements customers. This means that the customer receives some of its production capacity and production energy needs from its generator and the remaining amount from the utility. Partial requirements customers necessarily rely on the utility to provide back-up power, or production capacity, to serve their entire load if the generator is not available, either through an equipment outage or removal, or in the case of solar, other factors such as cloud cover or darkness. This back-up power must include a reserve margin, consistent with system power plant requirements.

Q. WHAT ARE APS'S PARTIAL REQUIREMENTS RATES?

A. APS currently has partial requirement rate rider schedules EPR-2, EPR-6 Legacy (frozen), EPR-6 (not frozen), RCP, E-56 R and E-56 for customers with on-site generation. EPR-2 applies to on-site generators less than or equal to 100 kW-ac in size. EPR-6 Legacy and RCP apply specifically to residential solar generation. For business customers, EPR-6 applies to the net metering program, and E-56 R and E-56 apply to renewable and non-renewable generation, respectively, for generators greater than 100 kW in size.

Q. ARE CUSTOMERS SPECIFICALLY CHARGED FOR BACK-UP POWER UNDER THESE RATES?

A. The rates for larger generators (>100 kW) typically have specific charges for back-up power services, while the rates for smaller generators (<=100 kW) typically do not expressly charge the residential solar customers for back-up services.[12]

Q. DOES THIS MEAN THAT SMALLER SOLAR GENERATORS DO NOT REQUIRE APS TO BACK UP THEIR SYSTEMS?

A. No. Back-up power service and costs still exist, even though APS does not specifically charge the individual customer a back-up fee for it. The fact that there is no charge for back-up service for these smaller solar customers means that the related costs are paid for by all non-solar customers in general rates. The result is also a revenue deficiency for the solar classes in the COSS, a key reason for performing a COSS specific to the residential solar classes.

Q. WHAT FACTORS ARE IMPORTANT WHEN CONSIDERING THE APPROPRIATE COST FOR BACK-UP PRODUCTION CAPACITY SERVICE FOR RESIDENTIAL SOLAR CUSTOMERS?

A. The amount of back-up production capacity service a solar customer needs depends on several factors, including: (1) the availability of the solar generator to serve the customer's load throughout the year, especially during critical high load hours or system emergencies; (2) the physical dependability of the generator; and (3) the customer's obligation (contractual or otherwise) to operate the generator and serve an expected portion of their load. These combined factors are often expressed with terms such as "firmness," "resource adequacy," "capacity value," "reliability," "effective load carrying capability" and others, each of which has its own definition and purpose. However, the core issue is the amount of solar generation capacity

[12] Some residential legacy solar customers served under the EPR-6 Legacy rate pay an LFCR DG charge. This charge has been frozen since September 1, 2017.

that can be dependably relied on to serve the customer's load during critical peak hours.

Q. DO APS'S PARTIAL REQUIREMENTS RATES INCLUDE A DEFINITION OF "FIRMNESS"?

A. Yes. APS's partial requirement rate schedules and riders include definitions of firm and non-firm power, which provide some guidance on this issue. The "firm power" definition assesses whether the power is available to the utility when needed, and evaluates the expected or demonstrated reliability of the supply compared with the reliability of the utility's generation. "Non-firm power," on the other hand, is defined as power supplied "at the customer's option," where no firm guarantee is provided, and the power can be interrupted by the customer at any time. These definitions are generally consistent with the factors discussed above in terms of availability, dependability, and the customer's obligation to supply the power. Examples of these definitions (as shown in Partial Requirements Rate Rider EPR 2) are provided below:

> *Non-Firm Power is electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.*
>
> *Firm Power is power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.*

Q. PLEASE EXPLAIN THE PROBLEM CONCERNING THE AVAILABILITY OF SOLAR GENERATION TO SERVE THE RESIDENTIAL LOAD DURING SUMMER PEAK HOURS.

A. A key issue for assessing the firmness of on-site solar generation is its availability to serve the customer's load, especially during critical peak hours, which typically occur in the late afternoon and early evening hours in the summer.

Figure 3 shows the residential class loads during the summer, along with the availability of the solar generation for the critical peak hours of 3 p.m. to 8 p.m., where the load is typically 91% or more of the peak hour. The third column reflects the information for the hour 5 p.m. to 6 p.m., which is typically both the coincident system peak hour (CP) and the residential class peak hour (NCP). Figure 3 also provides the information from four assessment points: the average of the four summer monthly CP days (4-CP), the average of the four summer monthly residential class peak days (4-NCP), the average of all core summer days that are at least 90% of the class peak, and the average over all core summer days. These four assessment points provide a very robust look at this issue.

Notice that the residential load remains very high and consistent throughout the entire 3 p.m. to 8 p.m. critical peak period. For example, looking at the 4-CP data, the residential load was 4,043 MW in the 5 p.m. to 6 p.m. system peak hour. It remained almost as high at 3,980 MW at hour 6 p.m. to 7 p.m., which is 98% of the peak hourly value, or a mere 2% drop off. Similarly, in the hour 7 p.m. to 8 p.m., the load continued to remain very high at 3,756 MW, which is 93% of the peak hourly value, only a 7% drop off.

Contrast the foregoing with the availability of the solar generation during the same hours. Again, looking at the 4-CP information, the solar generation was already dropping to 207 MW at the 5 p.m. to 6 p.m. peak hour from 373 MW in the prior hour. An additional significant drop to 69 MW followed in the hour 6 p.m. to 7 p.m., which is a 67% drop off from the peak hour; and at 7 p.m. to 8 p.m., when loads have only declined by 7% from the peak value, solar generation dropped to a mere 6 MW, which is a 97% drop off from the peak hour.

Further, this pattern of solar generation and the significant decline in output across the critical peak hours in the summer, when loads are at their highest, is consistent across each of the four points of assessment. For example, the solar generation drop off in hour 6 p.m. to 7 p.m. ranges from 65% to 69% across the four points of assessment. Likewise, the drop off in hour 7 p.m. to 8 p.m. ranges from 97% to 98%.

Figure 3. Residential Class Load and Solar Generation

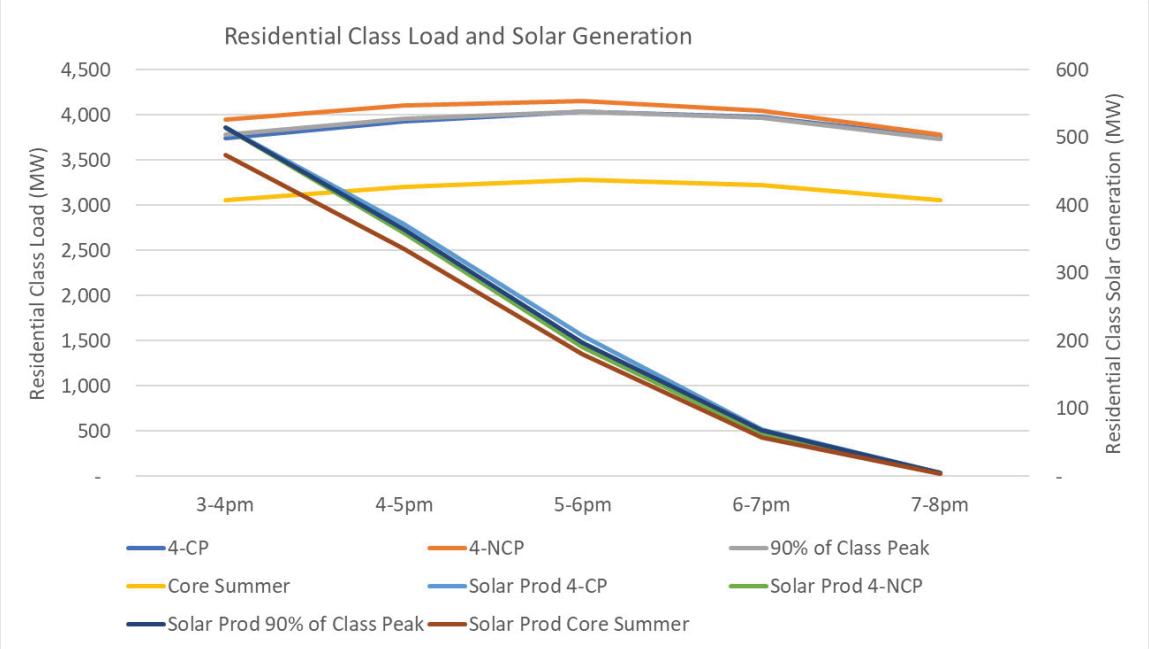
June-September Test Year, Hours 3 p.m. to 8 p.m., MW

	Peak Hour				
	3-4 pm	4-5 pm	5-6 pm	6-7 pm	7-8 pm
Residential Class Load					
4-CP days	3,745	3,929	4,043	3,980	3,756
class peak 4-NCP days	3,951	4,109	4,159	4,052	3,785
All days >= 90% of class peak	3,788	3,956	4,041	3,966	3,737
All core summer days	3,060	3,202	3,288	3,225	3,057
Residential Solar Generation					
4-CP days	514	373	207	69	6
class peak 4-NCP days	516	360	191	62	5
All days >= 90% of class peak	515	364	197	67	5
All core summer days	474	335	180	57	4

Q. WHAT IS YOUR CONCLUSION CONCERNING THE AVAILABILITY OF RESIDENTIAL SOLAR POWER?

A. As shown in Figure 4 below, residential loads are high across the entire 3 p.m. to 8 p.m. critical peak hours in the core summer months, but solar generation declines significantly over these same hours, it is evident that the generator does not have sufficient availability to provide the necessary production capacity to serve the home. It has a strong availability in hours 3 p.m. to 4 p.m. and 4 p.m. to 5 p.m., but declining availability at the 5 p.m. to 6 p.m. system peak hour, more significantly reduced availability at 6 p.m. to 7 p.m., and almost no availability at 7 p.m. to 8 p.m. As a result, the residential solar customer will require significant back-up power (or production capacity) from APS to reliably serve the home's load during summer critical peak hours.

Figure 4. Residential Class Load and Solar Generation



Q. IS THE COST FOR THE BACK-UP POWER ALREADY CAPTURED IN THE COSS FOR THE DELIVERED LOAD?

A. Only partially. Using the A&P cost allocation method, the production capacity cost for the delivered load (the portion of the home's consumption that is supplied by APS) is based on the solar customers' 4-CP delivered demand and the annual energy supplied by APS. The 4-CP delivered demand would be inversely related to the solar generation provided in Figure 4. As solar generation declines, delivered load increases for a given level of total demand (or site load) in the home. Because the 4-CP delivered demand is based on the load at 5 p.m. to 6 p.m., it already captures the solar generation drop off from 4 p.m. to 5 p.m. Therefore, that drop off will be excluded from any assessment of back-up power costs.

Conversely, the subsequent and further decline in solar generation in the hours 6 p.m. to 7 p.m. and 7 p.m. to 8 p.m., and the concomitant increase in the delivered demand, is not reflected in the allocated costs, because the "peak" part of the A&P method is only based on the delivered load at hour 5 p.m. to 6 p.m. The increased critical peak load resulting from the solar generation drop off from 6 p.m. to 8 p.m., which must be served by APS, is not captured in the A&P calculation. Technically, the "average" part of the A&P method would capture a very small part of this cost because the annual energy for the delivered load would also increase from the additional load at 6 p.m. to 8 p.m. However, this impact would be de minimis because this increase of energy during a few critical peak hours would represent only a very small percentage of the customer's total annual consumption of delivered energy.

Q. HOW DID APS ASSESS THE DEPENDABILITY FACTOR OF RESIDENTIAL SOLAR GENERATION?

A. I am using the term "dependability" to generically refer to the performance of the solar generator: it may have limited availability to serve load in certain peak hours, but when it is supposed to be available, how well does it actually run? To assess this factor, I considered several issues.

First, residential solar is comprised of a portfolio of thousands of individual generators, which enhances overall dependability. If one generator is experiencing an outage during a critical peak hour, it would only represent a very small portion of total solar generation supply. In addition, residential solar is located on the distribution grid and, therefore, not susceptible to any interruptions, cuts, or congestion issues on the transmission grid enhancing its dependability.

Next, solar customers have a strong incentive to keep their systems running as much as possible, especially those that are paying off a solar lease or loan. In fact, some leases may include a maintenance contract. Such an incentive also enhances dependability.

Conversely, the primary issue that would negatively impact the dependability of residential solar is the weather factor. There is a risk that cloud cover could significantly reduce the solar generation and this could potentially occur during critical peak hours. Furthermore, the cloud cover could impact many generators at the same time, thus reducing the ability to diversify the outage over the thousands of generators.

To assess this issue, I looked at the total solar generation for the core summer months and identified days when the output dropped significantly during the peak hours. This is not assessing the generation drop off across the peak hours in a day, which is the availability issue. Rather, it reflects the drop off in generation in similar hours across different days. I also reviewed the variability, or standard deviation, of the solar generation for each peak hour across the various core summer days. The standard deviation of the generation within each critical hour reflects the range of generation that can be depended on to serve load and the associated dependability or riskiness of the generation. The higher the standard deviation, the lower the dependability.

Q. WHAT WERE THE RESULTS OF YOUR ASSESSMENT OF THE VARIABILITY OF TOTAL SOLAR GENERATION?

A. The results for the lowest solar generation days are shown in Figure 5. As shown, there were a number of summer days where the solar generation dropped off significantly in the 3 p.m. to 8 p.m. hours. For example, on day 8/31, the total residential solar generation dropped to 24 MW in hour 5 p.m. to 6 p.m. from an average amount for core summer days of 180 MW for the same hour. The solar generation at 5 p.m. to 6 p.m. for all the days on Figure 5 ranges from 24 MW to 95 MW, each of which is a significant decline from the core summer average. The residential class load at 5 p.m. to 6 p.m. for the corresponding days is also provided in Figure 5. As shown, some of the days with low solar generation also had relatively lower residential loads (e.g., days 7/23, 9/26, 9/27, and 9/29). However, there were a couple days with low solar generation where the residential loads were comparatively high. These days include 7/11 and 7/21. The latter are the concerning days for the determination of the dependability of solar generation.

Figure 5. Residential Solar Generation, Lowest Days

June-September Test Year MW

Date	Solar Generation 3-4 (pm)	4-5 (pm)	**5-6 (pm)**	**Residential Load** 5-6 (pm)
8/31	156	65	24	2,185
7/23	75	55	40	1,616
9/26	122	109	44	1,585
9/29	270	146	45	1,828
9/23	353	201	48	2,724
9/27	270	165	66	1,863
9/24	380	215	69	2,164
9/28	359	214	70	2,122
9/30	421	250	76	2,020
9/18	233	138	78	2,485
7/11	**462**	**237**	**88**	**4,008**
9/17	329	223	89	2,809
9/25	438	271	94	2,598
7/21	**407**	**207**	**95**	**3,534**

The standard deviation information is provided in Figure 6. This figure shows the variability of the solar generation across the summer days for each of the critical peak hours. This statistic indicates how disperse the solar output values were over all the summer days. A higher standard deviation indicates a higher range of expected solar output in the hour and the lower the dependability of the solar generation.

If solar generation is normally distributed, then approximately 68% of the daily values for any given hour will lie within (+/-) one standard deviation unit of the mean, and about 95% will lie within two standard deviation units of the mean.[13] For example, as shown, the standard deviation of solar generation in the 5 p.m. to 6 p.m. peak hour for core summer days is 62 MW, while the average generation for the same hour is 180 MW (from Figure 6). This means that 68% of the daily values will fall in the range of 118 to 242 MW (180 +/- 62) and about 95% of the values will fall in the range of 56 to 304 MW (180 +/- 2 X 62). Thus, if you were trying to predict the total solar generation that could be depended on, during a summer day at the 5 p.m. to 6 p.m. peak hour, the average amount of 180 MW would be a good estimate. However, the actual amount could vary significantly from day to day. In fact, the range of possible values that would contain the right answer, 95% of the time, would be 56 to 304 MW, a significant spread.[14]

Q. ARE THERE ANY OTHER POINTS OF INTEREST YOU WOULD LIKE TO MAKE?

A. As shown on Figure 6, the standard deviation computed over the top 10% load days is lower than the standard deviation for all summer days. For example, the standard deviation over the top 10% load days for hour 5 p.m. to 6 p.m. is 41 MW compared to the 62 MW for all summer days.

[13] The precise number is 1.96 standard deviation units for a 95% confidence interval.
[14] Specifically, this means that in repeated samples or experiments the range will contain the true value of the mean in 95% of those experiments.

Figure 6. Residential Solar Generation
Mean and Standard Deviation
June-September Test Year MW

Hour (pm)	3-4	4-5	**5-6**	6-7	7-8
Mean (summer days)	474	335	180	57	4
Standard Deviation	102	85	62	35	4
Mean (top 10% days)	514	367	201	68	5
Standard Deviation	38	45	41	27	4

Q. WHAT DO YOU CONCLUDE ABOUT THE DEPENDABILITY AND RELIABILITY OF RESIDENTIAL SOLAR GENERATION?

A. The dependability is a mix: there is a large portfolio of thousands of solar generators, which diversifies and lessens the impact of any single generator outage; there is a high incentive for customers to keep the generators running as much as possible; and the solar generators are located on the distribution grid and therefore not susceptible to transmission related interruptions. Each of these factors increase dependability.

On the other hand, the actual output has a variability across different summer days in the peak hours that is not insignificant, which lessens dependability. On the plus side, this variability is lower for the top load days in the summer. Finally, the solar generation is susceptible to weather related interruptions that could impact many generators at the same time. Such interruptions were observed in a number of days in the core summer months in the Test Year. While many of these general

interruptions occurred on particular summer days when the residential load was not that high, some occurred during relatively high load days.

Q. PLEASE DESCRIBE THE LAST FACTOR FOR FIRMNESS, THE CUSTOMER'S OBLIGATION TO SUPPLY POWER.

A. The final concept for assessing the firmness of solar power is the level of obligation on the customer to provide the power, the guaranteed delivery of the power by the customer, or the level of customer optionality to provide the power. The definitions of firm and non-firm power in APS's partial requirements rates include terms such as "available upon demand" by the utility, "firm guarantee," and "customer's option." In determining the firmness of the solar power for a COSS, the solar customer has a strong incentive to run their generator as much as possible. Nevertheless, the complete lack of any delivery requirements or restrictions to customer optionality does have a negative impact, albeit a relatively modest one, on the dependability.

Q. WHAT IS YOUR OVERALL CONCLUSION ON THE FIRMNESS OF RESIDENTIAL SOLAR POWER?

A. Considering the three factors and the data and concepts presented, residential solar generation has a significant reduction in firmness for the limited availability over the summer peak hours; has a medium reduction in firmness for the dependability issue; and a modest reduction in firmness for the customer optionality issue. So, if you start with 100% firm power, the reduction for limited availability would be in the 30% to 50% range, the reduction for dependability would be 10% to 20%, and the reduction for customer optionality would be 10%. Overall, the reduction in firmness would be in the range of 50% to 80%. Stated the other way, the firmness or capacity value of residential solar generation during summer peak load hours would be in the range of 20% to 50%. For the solar COSS, we used the firmness value of 40%, which means that APS must supply back-up production capacity for

60% of the self-supply portion of the solar generation to provide reliable service to the solar customer.

Q. HOW DID APS DETERMINE THE COST FOR BACK-UP POWER FOR RESIDENTIAL SOLAR CUSTOMERS?

A. The cost for back-up power for solar customers was determined by first applying the 60% non-firm factor to the total 4-CP of the self-supply portion of solar generation to compute the total amount of back-up power service required from APS. The back-up amount was then multiplied by the average Test Year cost per kW for production capacity for the total residential class to derive the back-up costs included in the COSS. This calculation is detailed in Attachment JRM-06DR.

Q. HOW WERE THE CAPACITY RESERVE COSTS DETERMINED FOR THE COSS?

A. The capacity reserve costs were derived by applying the Company's standard 15% reserve requirement to the 40% firm portion of the solar generation for self-supply at the 4-CP hours. This MW level of required reserves was multiplied by the average cost per kW for production demand for the residential class in the COSS. The reserves for the 60% non-firm portion of the solar generation for self-supply are already captured in the back-up production demand costs because the required back-up MW were evaluated at the average production demand costs for the residential class, which includes the cost of reserves. The results are provided in Attachment JRM-06DR.

Q. ARE ALL THE RESERVES ALREADY CAPTURED IN THE BACK-UP COSTS?

A. No, just the non-firm portion as discussed above. The firm portion of the solar generation, the 40%, also requires reserves just as does APS-supplied power. Firmness and reserves are separate concepts. Firmness provides sufficient and reliable capacity to serve the load of the home under normal or expected conditions.

Reserves provide an additional buffer in case the actual system load or total system generation is significantly different from the expected levels.

Q. PLEASE DISCUSS ADDITIONAL GENERATION SERVICES THAT ARE NOT SUPPLIED BY THE SOLAR GENERATOR.

A. In addition to firm power and reserves, the solar home also needs a variety of generation related services that cannot typically be supplied by the solar generator. These include, for example: (1) the need for the generation to increase and decrease moderately to follow the load in the home in every instant throughout the day, (2) the costs to integrate the solar generator with the utilities entire generation portfolio, (3) the need for the generator to significantly ramp up and down when needed, and (4) the need to provide a significant power burst for a short instant to be able to serve major motor loads, such as an air conditioner compressor.

Like the reserve power costs, these additional generator services will only apply to the non-firm portion of the solar generation used for self-supply—the 60%. These services would already be captured through the conventional generation supplied by APS in the back-up power. The additional cost for these services were evaluated at the cost for similar services in the wholesale power market on a cost per kWh basis and applied to 60% of the total annual kWh of solar generation. The calculation and results are detailed in Attachment JRM-06DR.

Q. ARE THERE SIMILAR COSTS RELATED TO THE TRANSMISSION SYSTEM THAT SOLAR CUSTOMERS CAUSE?

A. Yes. The firmness determination for solar customers related to the transmission system is very similar to that discussed above regarding back-up power. The back-up transmission cost for solar customers was derived by first applying the 60% non-firm factor to the total 4-CP of the self-supply portion of solar generation to compute the total amount of back-up transmission service required from APS.

Then, this back-up amount was multiplied by the average Test Year cost per kW for transmission capacity for the total residential class to derive the back-up costs included in the COSS. This calculation is detailed in Attachment JRM-06DR.

Q. WHAT COST RECOVERY SHOULD SOLAR CUSTOMERS CONTRIBUTE TO THE PRIMARY DISTRIBUTION GRID?

A. Although residential solar generation is located at the home, the customer is still connected to the grid and relies on the grid in two ways: one for reliable electrical service and a second for exporting excess power to the grid. I will address the reliability related costs here and discuss the export related costs separately below.

Similar to production capacity, the utility provides back-up grid services to the solar customer and incurs costs for those services. These are not extra or special costs attributed solely to solar customers. Rather they are standard grid costs that are shared by all customers, that are used by solar customers, but not captured in the allocated cost for the delivered load.

The grid back-up costs are derived in a similar manner to the production capacity back-up costs. A non-firm percentage factor is determined and applied to the self-supply portion of solar generation, and evaluated at the 4-NCP summer hours of the total residential class. The resulting kW of required grid back-up is multiplied by the average cost for the portion of primary grid costs that are allocated on a demand basis to the residential class.

Q. HOW DID YOU ASSESS THE FIRMNESS LEVEL FOR SOLAR POWER CONCERNING THE PRIMARY GRID?

A. The assessment of the solar firmness level for the primary grid is similar to the assessment for production capacity detailed above. It is driven mostly by the availability and dependability of the solar power and to a much lesser extent on the

customer optionality factor. The thought process is the same—if the solar power is not completely available during high load hours, if it is not completely dependable when it is available, and if there is no obligation or recourse on the customer to supply the power, then the power is partially non-firm and the utility must step in and provide primary grid services to supply power to the home.

For the primary grid assessment, the solar availability factor is based on the 4-NCP hours in June through September, rather than the 4-CP that was used for production capacity. The other two factors are identical to the assessment for production capacity.

However, in reviewing the 4-CP and 4-NCP hours, the information is very consistent. As shown in Figure 7, most of the CPs and NCPs occur on hour 5 p.m. to 6 p.m., with one of the NCPs occurring on hour 4 p.m. to 5 p.m. Additionally, the monthly NCPs occur within a few days of the CP, with one (August) occurring on the same day and the same hour. In addition, the percentage drop off in load and solar generation in the hours 6 p.m. to 7 p.m. and 7 p.m. to 8 p.m. are almost identical between the 4-CP and 4-NCP assessment.

Given the consistency between the CP and NCP in terms of the availability of solar generation and given that the other three factors are not dependent on CP versus NCP information, the assessment used the same 40% firmness factor (60% non-firm) for solar generation for the primary distribution grid as was used for production and transmission capacity.

Figure 7. Residential Class CP and NCP

June-September Test Year MW

	CP		NCP	
	Day	**Hour (pm)**	**Day**	**Hour (pm)**
June	10	5-6	12	5-6
July	8	5-6	10	4-5
August	4	5-6	4	5-6
September	9	5-6	12	5-6

Q. HOW WERE THE PRIMARY GRID BACK-UP COSTS CALCULATED?

A. The back-up cost for the primary grid was derived by applying the 60% non-firm factor to the self-supply portion of solar generation occurring at the 4-NCP of the residential class. This required kW of grid services was multiplied by the average cost per kW for the primary grid for the residential class from the COSS; specifically, the portion of these costs that were allocated by demand. The details and results of this calculation are provided in Attachment JRM-06DR.

Q. HOW DID APS EVALUATE THE GRID COSTS FOR EXPORT POWER?

A. Export power is the solar generation in any instant that is not consumed in the home, but rather flows back to the utility grid. Because the solar customer requires and uses the grid to facilitate export power, those grid costs should be reflected in the COSS. APS derived this cost by applying the average cost per kWh for the primary distribution system for the total residential class to the total kWh of export power. Similar to the calculation of back-up grid costs, the portion of primary costs that were allocated on a customer basis were excluded in this calculation. The data and results are provided in Attachment JRM-06DR.

Q. WHY WASN'T THIS COST EVALUATED USING AN NCP ALLOCATOR?

A. While an NCP allocator is typically used to determine the cost responsibility for primary distribution equipment, that method does not accurately reflect the cost for export power because solar customers export power in many non-peak hours of the year.

Q. WHAT ADDITIONAL SECONDARY DISTRIBUTION COSTS WERE INCLUDED IN THE SOLAR COSS?

A. Secondary distribution costs include equipment such as the line transformer, the service drop and other point-of-delivery items necessary to connect the customer to the grid. The secondary equipment is designed to serve the loads in a home, or a small group of homes. As such, the equipment cannot be re-sized or reduced when a customer installs a solar generator. Further, any excess capacity of secondary equipment cannot be "shared with" or used to serve other homes. Thus, a solar generator does not reduce any secondary distribution costs.

Secondary distribution costs that were already allocated on a customer basis are already included in the COS for the delivered load for the solar class and, therefore, no additional costs need to be added in the solar COSS. However, secondary equipment that were allocated on a demand basis are only partially captured in the COS for delivered load. The remaining portion needs to be added back to the class in the solar COSS.

Q. WAS THE NET COST OR NET VALUE OF THE EXPORT POWER TRANSACTIONS INCLUDED IN APS'S ANALYSIS?

A. Yes. Up to this point, the solar COS has included the elements of solar power that impact the utility's cost of service related to base rates. However, the solar customers also participate in transactions with APS for the export power, where

the exports are either net metered on the customer's retail bill or purchased by APS at one of several purchase rates. In addition, the export power has a value to APS, based on avoided costs. Thus, the final element of the solar COS assesses the net cost or net value, whichever is higher, of the export power transactions.

Q. HOW WERE THE AVOIDED COSTS OF THE EXPORT POWER TRANSACTIONS EVALUATED?

A. The export power was valued at the non-firm avoided cost rate in rate schedule EPR-6, which is the rate at which net metering customers sell back excess power at the end of the year. The non-firm designation and value is appropriate here because the export power is a random flow of energy at any instant, rather than a certain amount that can be relied on or called upon by APS when needed. There are no obligations on the customer to supply a certain amount of power or any repercussions for not delivering power when requested.

Q. HOW WERE THE EXPORT PURCHASE COSTS DETERMINED?

A. As explained above, some of the export power is net metered on the customer's bill, while other amounts are purchased at one of APS's purchase rates. The latter includes rate rider schedules EPR-2, EPR-6, and RCP.

The net metered power is already factored into the assessment because the COSS compares the cost of service with the annual class revenue during the Test Year, which is already reduced by the net-metered amounts.

The export power that was purchased at the three purchase rates was included as recorded in our power accounting system for the Test Year. These amounts were also tested with individual calculations of the amount of export energy for each category multiplied by the applicable purchase rate, to ensure consistency with the value side of the calculation. The cost of EPR-2 and EPR-6 purchases are

essentially a wash with the value side of the computation because the purchase rates are based on, and equal to, the non-firm avoided cost value of transaction. However, because the export energy for these purchases were included in the export value, they also need to be included in the export purchase cost for consistency.

Q. WHAT WAS THE NET IMPACT OF THE EXPORT POWER TRANSACTIONS?

A. The net impact to the COSS from the export power transactions were $49.3 million. The details are provided in Attachment JRM-06DR.

Q. WHAT ARE THE OVERALL RESULTS OF THE SOLAR COSS FROM A BOTTOM-UP PERSPECTIVE?

A. Overall, with all the adjustments discussed, the results of the COSS for the solar classes are shown below in Figure 8.

Figure 8. Solar Cost of Service

(Bottom-Up Approach)

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
% COS Recovered	**34.8%**	**63.2%**	**47.0%**	**51.9%**

X. FAIR VALUE RATE OF RETURN

Q. WHAT IS APS'S FVRB AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR?

A. As shown on SFR Schedule A-1, APS's FVRB is $16.6 billion and the current fair value rate of return (FVROR) is 1.43% as reflected on SFR Schedule A-1, line 3.

Q. HOW WAS THE FAIR VALUE RATE BASE DETERMINED?

A. APS used the Commission approved methodology of averaging the OCRB and RCND in the calculation of FVRB. APS witness Elizabeth A. Blankenship's testimony describes this calculation in more detail.

Q. DID APS PERFORM A CALCULATION TO ADDRESS THE APPROPRIATE LEVEL OF RETURN ON FVRB?

A. Yes. The after-tax return on the Fair Value Increment (FVI) is shown on SFR Schedule A-1, line 9, and the calculation is shown in Attachment JRM-07DR.

Q. IS THE TREATMENT CONSISTENT WITH THE METHOD USED IN APS'S LAST RATE CASE?

A. Yes.

Q. CAN YOU EXPLAIN HOW THE FAIR VALUE RATE OF RETURN WAS CALCULATED?

A. Generally, APS calculated the rate of return to be applied to the fair value rate base (FVRB) as follows:

- FVRB is divided into three components:

  (1) The FVI is calculated by subtracting the OCRB from the FVRB to determine the portion of FVRB in excess of the OCRB;

  (2) Debt component of OCRB is calculated by multiplying the Company's adjusted Test Year debt percentage (48.07%) by the OCRB; and

  (3) Equity component of OCRB is calculated by multiplying the Company's adjusted Test Year equity percentage (51.93%) by the OCRB.

- Next, a return component of 1.0% is applied to the FVI. Using the 1.0% return for the FVI, 3.85% return on the debt component and 10.25% on the equity component, a new fair value weighted average cost of capital is calculated.

- The fair value weighted average cost of capital is applied to the FVRB and the result is compared to the original cost increase in revenue requirement of $689.5 million reflected on SFR Schedule A-1, line 8. The difference between those two values indicates that the after-tax return on the FVI is $82.8 million, as reflected on SFR Schedule A-1, line 9. Further detail is provided in Attachment JRM-07DR.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Index for Sponsorship of Standard Filing Requirements	
SFR Number	**Witness**
A-1	Mr. Moe
A-2*, A-3, A-4, A-5	Ms. Blankenship
B-1*, B-2*[1], B-3*, B-4, B-4a*, B-5	Ms. Blankenship
C-1*	Ms. Blankenship
C-2*[1] (Columns 1-5)	Ms. Blankenship
C-2 (Columns 6-8)	Mr. Moe
C-2*(Columns 9-10, 19, 22-24)	Ms. Hobbick
C-2* (Columns 11-13, 20, 25-59)	Ms. Blankenship
C-2* (Columns 14-16, 18) [2]	Ms. Hobbick/Ms. Blankenship
C-3	Ms. Blankenship
D-1, D-2, D-3, D-4	Ms. Blankenship
E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9	Ms. Blankenship
F-1*, F-2, F-3, F-4	Ms. Blankenship
G-1, G-2, G-3, G-4, G-5, G-6, G-7	Mr. Moe
H-1, H-2, H-3, H-4, H-5	Ms. Hobbick

*Mr. Moe sponsors the ACC jurisdictional amounts that are computed based on the Cost of Service Study.

[1]Mr. Tetlow discusses the details of post-Test Year plant projects included in the pro formas

[2]Ms. Hobbick address the rate impacts of the proposed adjustment mechanism pro formas

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

SUMMARY OF RESULTS	ELECTRIC TOTAL	ALL OTHER	ACC JURISDICTION	RETAIL					
				RESIDENTIAL	GENERAL SERVICE	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 9,832,767,730	$ 12,364,736	$ 9,820,402,994	$ 5,644,799,323	$ 4,082,038,221	$ 72,753,671	$ -	$ 17,771,176	$ 3,040,603
TRANSMISSION PLANT IN SERVICE	3,414,532,481	3,414,532,481	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	7,763,311,806	47,825	7,763,263,981	5,771,375,635	1,782,547,308	39,319,272	-	107,314,282	62,707,483
GENERAL & INTANGIBLE PLANT	2,381,362,366	201,416,194	2,179,946,172	1,453,304,722	704,067,273	13,388,009	-	5,155,410	4,030,757
LESS: RESERVE FOR DEPRECIATION	(8,525,604,548)	(1,097,516,640)	(7,428,087,908)	(4,725,933,842)	(2,593,273,764)	(48,993,629)	-	(39,405,564)	(20,481,109)
MATERIALS, SUPPLIES & PREPAYMENTS	611,970,887	60,472,722	551,498,165	330,308,502	212,708,503	4,215,207	-	2,947,009	1,318,944
MISCELLANEOUS DEFERRED DEBITS	30,089,000	1,720,232	28,368,768	17,044,088	10,988,967	218,082	-	81,530	36,100
OTHER DEFERRED CREDITS	(1,293,452,000)	(17,026,530)	(1,276,425,470)	(727,913,564)	(534,912,652)	(9,913,421)	-	(2,973,607)	(712,226)
OPEB	568,515,119	50,048,476	518,466,642	340,355,139	172,685,905	3,309,901	-	1,257,084	858,614
WORKING CASH	(105,488,059)	(25,067,681)	(80,420,378)	(56,857,229)	(21,946,896)	(396,727)	-	(775,431)	(444,095)
REGULATORY ASSETS	(824,250,000)	41,487,508	(865,737,508)	(545,026,594)	(305,547,855)	(5,845,629)	-	(6,239,475)	(3,077,956)
ACCUM. DEFERRED TAXES	(2,354,271,572)	(1,460,221)	(2,352,811,351)	(1,539,735,347)	(772,580,780)	(14,868,658)	-	(16,688,709)	(8,937,857)
OPERATING LEASES	22,468,854	5,217,275	17,251,579	16,988,475	228,891	(24,596)	-	(6,920)	65,729
DECOMMISSIONING FUND	1,422,493,893	1,706,993	1,420,786,900	812,175,200	594,760,584	10,692,502	-	2,695,501	463,112
CUSTOMER ADVANCES	(336,198,398)	(30,943,932)	(305,254,466)	(59,671,221)	(244,998,747)	(12,256)	-	(571,951)	(290)
CUSTOMER DEPOSITS	(40,062,749)	-	(40,062,749)	(10,971,370)	(28,113,431)	(604,946)	-	(373,003)	-
PROFORMA ADJUSTMENTS	578,176,449	13,487,964	564,688,485	346,787,908	210,941,965	3,916,486	-	2,074,849	967,277
TOTAL RATE BASE	**13,146,361,258**	**2,630,487,403**	**10,515,873,855**	**7,067,029,827**	**3,269,593,492**	**67,153,269**	**-**	**72,262,181**	**39,835,086**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,468,594,702	70,581,514	3,398,013,188	1,822,674,883	1,514,041,713	32,579,215	-	20,087,962	8,629,415
PRO FORMA TO BASE REVENUES FROM RATES	(21,200,909)	-	(21,200,909)	(3,365,597)	(14,959,440)	(2,243,274)	-	(790,435)	157,837
SURCHARGE & OTHER ELECTRIC REVENUES	513,230,298	51,966,846	461,263,452	255,683,960	198,871,253	4,903,633	-	1,432,620	371,985
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(209,593,326)	(181,152)	(209,412,174)	(125,392,120)	(80,790,128)	(2,446,293)	-	(569,054)	(214,579)
TOTAL OPERATING REVENUES	**3,751,030,765**	**122,367,208**	**3,628,663,557**	**1,949,601,127**	**1,617,163,399**	**32,793,281**	**-**	**20,161,093**	**8,944,658**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,021,289,826	(210,227,344)	2,231,517,171	1,208,003,895	993,085,522	21,984,448	-	6,569,697	1,873,608
ADMINISTRATIVE & GENERAL	169,603,050	19,344,934	150,258,116	99,361,524	49,309,448	945,539	-	377,981	263,624
DEPRECIATION & AMORT EXPENSE	677,267,319	82,200,289	595,067,030	383,811,293	202,226,210	3,862,423	-	3,366,763	1,800,340
OTHER EXPENSE ITEMS	26,436,176	2	26,436,174	15,111,845	11,066,601	198,955	-	50,156	8,617
TAXES OTHER THAN INCOME	227,125,941	39,350,683	187,775,259	126,833,797	57,157,070	1,133,875	-	1,709,652	940,865
PROFORMA ADJUSTMENTS	231,114,792	4,279,233	226,835,560	132,927,318	91,461,249	1,382,428	-	795,085	269,479
INCOME TAX	115,485,000	30,375,547	85,109,453	7,597,844	73,243,946	1,800,893	-	1,760,406	706,364
PROFORMA INCOME TAX ADJUSTMENTS	(113,749,642)	(1,563,146)	(112,186,496)	(64,035,299)	(46,065,908)	(1,496,407)	-	(516,963)	(71,919)
TOTAL OPERATING EXPENSES	**3,354,572,462**	**(36,239,804)**	**3,390,812,266**	**1,909,612,217**	**1,431,484,138**	**29,812,153**	**-**	**14,112,779**	**5,790,979**
OPERATING INCOME	**396,458,303**	**158,607,012**	**237,851,291**	**39,988,910**	**185,679,261**	**2,981,128**	**0**	**6,048,314**	**3,153,679**
RATE OF RETURN (PRESENT)	**3.02%**	**6.03%**	**2.26%**	**0.57%**	**5.68%**	**4.44%**	**0.00%**	**8.37%**	**7.92%**
INDEX RATE OF RETURN (PRESENT)	**1.0**	**2.0**	**0.8**	**0.2**	**1.9**	**1.5**	**-**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**4,259,739,586**	**110,656,184**	**4,149,083,401**	**2,497,857,334**	**1,590,509,398**	**33,326,209**	**0**	**18,697,489**	**8,692,971**
% OF TOTAL COST OF SERVICE (PRESENT)	**81.78%**	**63.79%**	**82.26%**	**74.11%**	**94.48%**	**94.01%**	**0.00%**	**102.81%**	**100.99%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**99.06%**	**63.79%**	**100.00%**	**89.44%**	**115.89%**	**116.14%**		**122.45%**	**116.76%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

SUMMARY OF RESULTS	RESIDENTIAL								
	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar TOU	R-Solar (Demand)	R-Basic (0-600kW)	R-Basic (601-999 kW)	R-Basic (1000+ kW)	R-TOU	R-Demand
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 488,801,299	$ 13,765,408	$ 226,940,302	$ 96,984,231	$ 729,443,030	$ 333,238,314	$ 132,175,064	$ 1,502,184,094	$ 2,121,267,582
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	427,762,293	10,724,735	236,059,559	88,538,724	1,113,504,688	373,356,538	118,752,094	1,509,174,525	1,893,502,478
GENERAL & INTANGIBLE PLANT	109,156,454	2,816,987	58,213,002	22,462,917	278,467,494	92,327,987	30,618,593	373,092,955	486,148,333
LESS: RESERVE FOR DEPRECIATION	(379,654,765)	(10,202,046)	(190,961,228)	(76,946,073)	(764,140,288)	(291,241,266)	(104,239,278)	(1,241,552,584)	(1,666,996,313)
MATERIALS, SUPPLIES & PREPAYMENTS	26,739,791	743,388	13,327,217	5,533,161	51,312,979	19,786,828	7,389,155	86,526,572	118,949,412
MISCELLANEOUS DEFERRED DEBITS	1,339,970	36,863	682,964	279,725	2,880,052	1,031,507	374,707	4,404,758	6,013,543
OTHER DEFERRED CREDITS	(61,948,660)	(1,754,410)	(29,247,255)	(12,504,593)	(98,592,720)	(42,789,137)	(16,895,238)	(192,426,130)	(271,755,422)
OPEB	25,859,221	673,719	13,638,113	5,312,496	63,508,712	21,481,611	7,233,324	87,635,388	115,012,553
WORKING CASH	(4,536,575)	(116,559)	(2,319,690)	(898,466)	(9,451,920)	(3,624,723)	(1,229,536)	(15,117,204)	(19,562,556)
REGULATORY ASSETS	(44,639,510)	(1,214,710)	(22,121,674)	(9,034,717)	(82,797,897)	(33,225,316)	(12,177,874)	(144,412,359)	(195,402,538)
ACCUM. DEFERRED TAXES	(122,483,951)	(3,256,157)	(62,415,890)	(24,862,531)	(254,697,399)	(95,687,809)	(33,621,425)	(405,102,179)	(537,608,004)
OPERATING LEASES	1,138,283	22,664	680,903	216,536	4,205,551	1,230,754	317,700	4,325,906	4,850,179
DECOMMISSIONING FUND	70,243,803	1,984,461	32,647,555	13,986,632	105,045,499	47,806,061	19,021,321	215,934,354	305,505,512
CUSTOMER ADVANCES	(1,941,352)	(100,878)	(1,869,304)	(803,835)	(8,858,012)	(3,752,413)	(1,696,196)	(17,798,968)	(22,850,262)
CUSTOMER DEPOSITS	(351,849)	(18,477)	(342,859)	(147,442)	(1,630,471)	(690,312)	(312,342)	(3,275,644)	(4,201,973)
PROFORMA ADJUSTMENTS	28,397,420	775,078	13,970,168	5,731,016	53,304,189	21,095,894	7,776,847	91,239,274	124,498,021
TOTAL RATE BASE	**563,881,873**	**14,880,066**	**286,881,882**	**113,847,782**	**1,181,503,488**	**440,344,517**	**153,486,917**	**1,854,832,757**	**2,457,370,546**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557	270,870,328	114,681,673	51,889,334	544,183,153	698,074,284
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,216)	(494,918)	8,763,675	(3,471,297)	1,613,889	(17,040,346)	9,032,112
SURCHARGE & OTHER ELECTRIC REVENUES	15,307,364	514,359	9,021,273	4,047,971	39,309,902	15,148,017	6,130,360	68,154,430	98,050,286
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(4,302,104)	(182,825)	(3,709,741)	(1,676,257)	(22,282,606)	(7,959,670)	(3,066,291)	(34,194,016)	(48,018,610)
TOTAL OPERATING REVENUES	**69,001,173**	**3,346,404**	**61,013,591**	**26,371,353**	**296,661,299**	**118,398,723**	**56,567,292**	**561,103,221**	**757,138,072**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	50,406,025	1,749,933	59,451,893	22,721,124	186,056,505	71,820,650	28,887,368	324,176,421	462,733,975
ADMINISTRATIVE & GENERAL	7,520,578	195,105	3,982,079	1,544,893	18,705,855	6,289,912	2,104,691	25,571,221	33,447,191
DEPRECIATION & AMORT EXPENSE	30,489,298	813,363	15,512,975	6,198,830	63,872,121	23,791,468	8,392,892	100,607,483	134,132,864
OTHER EXPENSE ITEMS	1,306,999	36,924	607,461	260,245	1,954,544	889,508	353,923	4,017,808	5,684,433
TAXES OTHER THAN INCOME	9,926,018	260,540	5,157,826	2,025,608	21,769,882	7,957,452	2,730,526	33,352,108	43,653,837
PROFORMA ADJUSTMENTS	14,602,470	426,680	5,817,556	2,659,724	17,175,327	5,734,260	3,285,072	29,078,911	54,147,318
INCOME TAX	(10,646,375)	17,732	(6,783,054)	(1,898,999)	(4,299,673)	1,425,617	2,685,800	16,851,473	10,245,322
PROFORMA INCOME TAX ADJUSTMENTS	(4,735,333)	(162,873)	(2,638,975)	(1,183,798)	(7,475,604)	(4,201,770)	(1,157,242)	(19,679,356)	(22,800,347)
TOTAL OPERATING EXPENSES	**98,869,679**	**3,337,405**	**81,107,761**	**32,327,626**	**297,758,959**	**113,707,095**	**47,283,030**	**513,976,068**	**721,244,594**
OPERATING INCOME	**(29,868,506)**	**8,999**	**(20,094,170)**	**(5,956,273)**	**(1,097,660)**	**4,691,627**	**9,284,262**	**47,127,153**	**35,893,478**
RATE OF RETURN (PRESENT)	**-5.30%**	**0.06%**	**-7.00%**	**-5.23%**	**-0.09%**	**1.07%**	**6.05%**	**2.54%**	**1.46%**
INDEX RATE OF RETURN (PRESENT)	**(1.8)**	**0.0**	**(2.3)**	**(1.7)**	**(0.0)**	**0.4**	**2.0**	**0.8**	**0.5**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**156,307,569**	**4,544,814**	**112,258,160**	**43,751,715**	**403,415,266**	**150,538,939**	**57,001,143**	**656,297,368**	**913,742,360**
% OF TOTAL COST OF SERVICE (PRESENT)	**37.73%**	**68.04%**	**50.38%**	**56.22%**	**70.44%**	**75.08%**	**95.25%**	**81.63%**	**78.86%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**45.56%**	**81.45%**	**60.41%**	**69.56%**	**85.12%**	**90.72%**	**115.26%**	**98.72%**	**94.92%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

SUMMARY OF RESULTS	GENERAL SERVICE								
	E-20 (Church Rate)	E-32 TOU (0-20 kW)	E-32 TOU (21-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-20 kW)	E-32 (21-100 kW)	E-32 (101-400 kW)
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 12,160,381	$ 5,579,743	$ 8,269,436	$ 30,602,927	$ 77,074,903	$ 53,274,445	$ 512,732,873	$ 795,188,536	$ 914,636,571
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	10,547,706	3,928,185	3,861,969	11,002,846	25,819,833	31,984,511	497,065,199	384,921,647	342,574,123
GENERAL & INTANGIBLE PLANT	2,445,496	1,214,554	1,469,386	4,792,058	11,769,093	8,672,309	134,584,485	146,015,666	140,898,091
LESS: RESERVE FOR DEPRECIATION	(9,260,148)	(4,104,653)	(5,343,821)	(18,588,426)	(46,047,273)	(35,767,346)	(425,372,911)	(518,926,029)	(554,997,907)
MATERIALS, SUPPLIES & PREPAYMENTS	672,766	332,228	434,043	1,617,636	3,951,065	2,866,356	31,302,821	40,606,126	45,650,594
MISCELLANEOUS DEFERRED DEBITS	32,668	17,402	22,573	82,749	201,571	137,750	1,656,371	2,129,779	2,302,222
OTHER DEFERRED CREDITS	(1,550,039)	(756,154)	(1,083,437)	(4,075,355)	(10,148,279)	(6,928,098)	(68,177,331)	(102,640,818)	(118,319,355)
OPEB	602,126	289,809	362,935	1,190,276	2,925,795	2,152,613	31,489,704	36,000,089	34,968,476
WORKING CASH	(111,203)	(37,811)	(46,341)	(138,153)	(349,419)	(361,739)	(4,672,280)	(4,762,256)	(4,709,748)
REGULATORY ASSETS	(1,123,463)	(479,000)	(626,526)	(2,231,525)	(5,518,937)	(4,438,012)	(48,569,682)	(60,059,151)	(66,559,654)
ACCUM. DEFERRED TAXES	(3,020,346)	(1,273,263)	(1,602,860)	(5,447,087)	(13,437,246)	(11,191,450)	(136,604,844)	(156,227,494)	(164,192,403)
OPERATING LEASES	21,251	3,935	2,345	(23,813)	(51,285)	587	1,274,737	631,860	(217,911)
DECOMMISSIONING FUND	1,752,220	816,547	1,204,013	4,484,015	11,264,979	7,747,836	74,342,056	115,275,494	133,048,734
CUSTOMER ADVANCES	(505,673)	(380,282)	(503,612)	(1,333,752)	(3,444,317)	(2,425,196)	(31,915,380)	(40,834,324)	(44,067,912)
CUSTOMER DEPOSITS	(73,495)	(55,316)	(73,245)	(193,861)	(500,661)	(352,540)	(4,641,920)	(5,937,292)	(6,406,665)
PROFORMA ADJUSTMENTS	694,802	317,780	432,230	1,540,647	3,835,158	2,811,882	31,538,290	41,785,723	45,728,213
TOTAL RATE BASE	**13,285,049**	**5,413,704**	**6,779,087**	**23,281,182**	**57,344,978**	**48,183,908**	**596,032,187**	**673,167,555**	**700,335,468**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,958,051	2,979,043	3,944,581	10,440,351	26,962,992	18,985,953	249,989,443	319,751,351	345,029,300
PRO FORMA TO BASE REVENUES FROM RATES	(51,315)	64,393	(248,666)	(524,002)	2,512,750	(240,838)	(3,267,610)	(3,615,921)	(4,925,494)
SURCHARGE & OTHER ELECTRIC REVENUES	563,836	385,003	474,487	1,507,987	3,447,597	2,673,587	30,357,537	43,080,394	45,613,844
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(271,375)	(212,394)	(236,290)	(526,766)	(1,110,721)	(1,162,244)	(16,682,851)	(21,841,740)	(19,790,485)
TOTAL OPERATING REVENUES	**4,199,197**	**3,216,044**	**3,934,112**	**10,897,569**	**31,812,618**	**20,256,458**	**260,396,519**	**337,374,083**	**365,927,166**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,882,082	1,561,672	2,030,311	7,443,789	18,081,818	13,597,127	132,496,905	190,870,127	212,800,995
ADMINISTRATIVE & GENERAL	174,646	83,505	103,866	337,248	828,760	615,551	9,168,890	10,337,005	9,939,782
DEPRECIATION & AMORT EXPENSE	743,035	327,566	418,768	1,436,225	3,546,477	2,804,897	34,534,062	40,787,325	42,860,244
OTHER EXPENSE ITEMS	32,603	15,193	22,403	83,434	209,606	144,162	1,383,264	2,144,901	2,475,610
TAXES OTHER THAN INCOME	245,808	100,119	119,412	395,307	966,477	872,680	11,153,375	11,654,488	11,964,822
PROFORMA ADJUSTMENTS	280,829	71,413	64,546	776,497	3,162,866	1,913,376	7,406,075	13,225,635	20,597,937
INCOME TAX	7,733	273,258	373,265	373,669	1,223,904	518,320	18,088,314	21,260,407	21,834,405
PROFORMA INCOME TAX ADJUSTMENTS	(147,909)	(53,794)	(135,396)	(450,293)	(431,935)	(815,547)	(6,708,113)	(9,520,283)	(11,157,074)
TOTAL OPERATING EXPENSES	**4,218,827**	**2,378,933**	**2,997,175**	**10,395,874**	**27,587,971**	**19,650,566**	**207,522,773**	**280,759,606**	**311,316,723**
OPERATING INCOME	**(19,630)**	**837,112**	**936,938**	**501,695**	**4,224,647**	**605,893**	**52,873,746**	**56,614,477**	**54,610,443**
RATE OF RETURN (PRESENT)	**-0.15%**	**15.46%**	**13.82%**	**2.15%**	**7.37%**	**1.26%**	**8.87%**	**8.41%**	**7.80%**
INDEX RATE OF RETURN (PRESENT)	**(0.0)**	**5.1**	**4.6**	**0.7**	**2.4**	**0.4**	**2.9**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,309,556**	**2,486,970**	**3,148,017**	**11,665,247**	**29,790,044**	**22,935,047**	**237,863,709**	**310,350,664**	**339,869,498**
% OF TOTAL COST OF SERVICE (PRESENT)	**75.64%**	**122.56%**	**117.97%**	**85.46%**	**98.04%**	**84.19%**	**104.59%**	**102.99%**	**100.89%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**91.06%**	**151.44%**	**145.29%**	**105.22%**	**122.58%**	**101.48%**	**128.36%**	**126.06%**	**124.03%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

SUMMARY OF RESULTS	GENERAL SERVICE E-32 (401+ kW)	E-34	E-35	AG-X
DEVELOPMENT OF RATE BASE				
PRODUCTION PLANT IN SERVICE	$ 742,288,876	$ 165,390,653	$ 509,157,006	$ 255,681,872
TRANSMISSION PLANT IN SERVICE	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	249,726,692	43,002,737	114,822,244	63,289,617
GENERAL & INTANGIBLE PLANT	112,720,666	24,744,695	76,652,908	38,087,866
LESS: RESERVE FOR DEPRECIATION	(443,091,368)	(95,361,908)	(289,804,980)	(146,606,994)
MATERIALS, SUPPLIES & PREPAYMENTS	37,759,747	8,395,890	26,129,012	12,990,218
MISCELLANEOUS DEFERRED DEBITS	1,920,565	435,534	1,374,309	675,474
OTHER DEFERRED CREDITS	(97,362,086)	(21,895,160)	(68,060,087)	(33,916,454)
OPEB	28,019,416	6,153,148	19,061,616	9,469,902
WORKING CASH	(3,424,888)	(638,631)	(1,740,757)	(953,668)
REGULATORY ASSETS	(53,150,663)	(11,312,539)	(34,111,854)	(17,366,848)
ACCUM. DEFERRED TAXES	(129,472,511)	(27,162,737)	(81,388,376)	(41,560,163)
OPERATING LEASES	(453,703)	(150,147)	(558,969)	(249,997)
DECOMMISSIONING FUND	108,391,564	24,219,412	74,749,071	37,464,644
CUSTOMER ADVANCES	(33,111,143)	(4,891,691)	(71,283,271)	(10,302,194)
CUSTOMER DEPOSITS	(4,812,982)	(710,299)	(2,857,985)	(1,497,169)
PROFORMA ADJUSTMENTS	36,877,857	8,090,630	24,817,250	12,471,504
TOTAL RATE BASE	**552,826,039**	**118,309,588**	**296,957,137**	**177,677,609**
DEVELOPMENT OF RETURN				
BASE REVENUES FROM RATES	259,201,950	38,252,968	153,916,079	80,629,651
PRO FORMA TO BASE REVENUES FROM RATES	304,925	2,210,724	(5,836,221)	(1,342,165)
SURCHARGE & OTHER ELECTRIC REVENUES	33,914,431	7,477,244	24,217,213	5,158,094
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(11,674,669)	(2,299,744)	(7,790,126)	2,809,278
TOTAL OPERATING REVENUES	**281,746,637**	**45,641,193**	**164,506,945**	**87,254,858**
OPERATING EXPENSES				
OPERATION & MAINTENANCE	174,962,433	40,524,545	127,343,842	68,489,878
ADMINISTRATIVE & GENERAL	7,938,614	1,737,196	5,372,885	2,671,500
DEPRECIATION & AMORT EXPENSE	34,114,284	7,299,435	22,144,386	11,209,505
OTHER EXPENSE ITEMS	2,016,825	450,648	1,390,850	697,101
TAXES OTHER THAN INCOME	9,318,267	1,895,042	5,587,087	2,884,186
PROFORMA ADJUSTMENTS	19,572,255	6,536,884	13,110,803	4,742,134
INCOME TAX	11,657,985	(2,451,006)	1,523,237	(1,439,545)
PROFORMA INCOME TAX ADJUSTMENTS	(7,616,253)	(1,632,430)	(6,595,338)	(801,544)
TOTAL OPERATING EXPENSES	**251,964,411**	**54,360,314**	**169,877,751**	**88,453,215**
OPERATING INCOME	**29,782,226**	**(8,719,121)**	**(5,370,807)**	**(1,198,358)**
RATE OF RETURN (PRESENT)	**5.39%**	**-7.37%**	**-1.81%**	**-0.67%**
INDEX RATE OF RETURN (PRESENT)	**1.8**	**(2.4)**	**(0.6)**	**(0.2)**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**277,152,418**	**64,408,170**	**186,169,924**	**99,360,135**
% OF TOTAL COST OF SERVICE (PRESENT)	**92.91%**	**62.61%**	**78.82%**	**78.05%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**117.75%**	**92.28%**	**94.31%**	**79.15%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

SUMMARY OF RESULTS	ELECTRIC TOTAL	ALL OTHER	ACC JURISDICTION	RETAIL					
				RESIDENTIAL	GENERAL SERVICE	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 9,832,767,730	$ 12,364,736	$ 9,820,402,994	$ 5,644,799,323	$ 4,082,038,221	$ 72,753,671	$ -	$ 17,771,176	$ 3,040,603
TRANSMISSION PLANT IN SERVICE	3,414,532,481	3,414,532,481	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	7,763,311,806	47,825	7,763,263,981	5,771,375,635	1,782,547,308	39,319,272	-	107,314,282	62,707,483
GENERAL & INTANGIBLE PLANT	2,381,362,366	201,416,194	2,179,946,172	1,453,304,722	704,067,273	13,388,009	-	5,155,410	4,030,757
LESS: RESERVE FOR DEPRECIATION	(8,525,604,548)	(1,097,516,640)	(7,428,087,908)	(4,725,933,842)	(2,593,273,764)	(48,993,629)	-	(39,405,564)	(20,481,109)
MATERIALS, SUPPLIES & PREPAYMENTS	611,970,887	60,472,722	551,498,165	330,308,502	212,708,503	4,215,207	-	2,947,009	1,318,944
MISCELLANEOUS DEFERRED DEBITS	30,089,000	1,720,232	28,368,768	17,044,088	10,988,967	218,082	-	81,530	36,100
OTHER DEFERRED CREDITS	(1,293,452,000)	(17,026,530)	(1,276,425,470)	(727,913,564)	(534,912,652)	(9,913,421)	-	(2,973,607)	(712,226)
OPEB	568,515,119	50,048,476	518,466,642	340,355,139	172,685,905	3,309,901	-	1,257,084	858,614
WORKING CASH	(105,488,059)	(25,067,681)	(80,420,378)	(56,857,229)	(21,946,896)	(396,727)	-	(775,431)	(444,095)
REGULATORY ASSETS	(824,250,000)	41,487,508	(865,737,508)	(545,026,594)	(305,547,855)	(5,845,629)	-	(6,239,475)	(3,077,956)
ACCUM. DEFERRED TAXES	(2,354,271,572)	(1,460,221)	(2,352,811,351)	(1,539,735,347)	(772,580,780)	(14,868,658)	-	(16,688,709)	(8,937,857)
OPERATING LEASES	22,468,854	5,217,275	17,251,579	16,988,475	228,891	(24,596)	-	(6,920)	65,729
DECOMMISSIONING FUND	1,422,493,893	1,706,993	1,420,786,900	812,175,200	594,760,584	10,692,502	-	2,695,501	463,112
CUSTOMER ADVANCES	(336,198,398)	(30,943,932)	(305,254,466)	(59,671,221)	(244,998,747)	(12,256)	-	(571,951)	(290)
CUSTOMER DEPOSITS	(40,062,749)	-	(40,062,749)	(10,971,370)	(28,113,431)	(604,946)	-	(373,003)	-
PROFORMA ADJUSTMENTS	578,176,449	13,487,964	564,688,485	346,787,908	210,941,965	3,916,486	-	2,074,849	967,277
TOTAL RATE BASE	**13,146,361,258**	**2,630,487,403**	**10,515,873,855**	**7,067,029,827**	**3,269,593,492**	**67,153,269**	**-**	**72,262,181**	**39,835,086**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,468,594,702	70,581,514	3,398,013,188	1,822,674,883	1,514,041,713	32,579,215	-	20,087,962	8,629,415
PRO FORMA TO BASE REVENUES FROM RATES	(21,200,909)	-	(21,200,909)	(3,365,597)	(14,959,440)	(2,243,274)	-	(790,435)	157,837
SURCHARGE & OTHER ELECTRIC REVENUES	513,230,298	51,966,846	461,263,452	255,683,960	198,871,253	4,903,633	-	1,432,620	371,985
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(209,593,326)	(181,152)	(209,412,174)	(125,392,120)	(80,790,128)	(2,446,293)	-	(569,054)	(214,579)
TOTAL OPERATING REVENUES	**3,751,030,765**	**122,367,208**	**3,628,663,557**	**1,949,601,127**	**1,617,163,399**	**32,793,281**	**-**	**20,161,093**	**8,944,658**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,021,289,826	(210,227,344)	2,231,517,171	1,208,003,895	993,085,522	21,984,448	-	6,569,697	1,873,608
ADMINISTRATIVE & GENERAL	169,603,050	19,344,934	150,258,116	99,361,524	49,309,448	945,539	-	377,981	263,624
DEPRECIATION & AMORT EXPENSE	677,267,319	82,200,289	595,067,030	383,811,293	202,226,210	3,862,423	-	3,366,763	1,800,340
OTHER EXPENSE ITEMS	26,436,176	2	26,436,174	15,111,845	11,066,601	198,955	-	50,156	8,617
TAXES OTHER THAN INCOME	227,125,941	39,350,683	187,775,259	126,833,797	57,157,070	1,133,875	-	1,709,652	940,865
PROFORMA ADJUSTMENTS	231,114,792	4,279,233	226,835,560	132,927,318	91,461,249	1,382,428	-	795,085	269,479
INCOME TAX	115,485,000	30,375,547	85,109,453	7,597,844	73,243,946	1,800,893	-	1,760,406	706,364
PROFORMA INCOME TAX ADJUSTMENTS	(113,749,642)	(1,563,146)	(112,186,496)	(64,035,299)	(46,065,908)	(1,496,407)	-	(516,963)	(71,919)
TOTAL OPERATING EXPENSES	**3,354,572,462**	**(36,239,804)**	**3,390,812,266**	**1,909,612,217**	**1,431,484,138**	**29,812,153**	**-**	**14,112,779**	**5,790,979**
OPERATING INCOME	**396,458,303**	**158,607,012**	**237,851,291**	**39,988,910**	**185,679,261**	**2,981,128**	**0**	**6,048,314**	**3,153,679**
RATE OF RETURN (PRESENT)	**3.02%**	**6.03%**	**2.26%**	**0.57%**	**5.68%**	**4.44%**	**0.00%**	**8.37%**	**7.92%**
INDEX RATE OF RETURN (PRESENT)	**1.0**	**2.0**	**0.8**	**0.2**	**1.9**	**1.5**	**-**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**4,259,739,586**	**110,656,184**	**4,149,083,401**	**2,497,857,334**	**1,590,509,398**	**33,326,209**	**0**	**18,697,489**	**8,692,971**
% OF TOTAL COST OF SERVICE (PRESENT)	**81.78%**	**63.79%**	**82.26%**	**74.11%**	**94.48%**	**94.01%**	**0.00%**	**102.81%**	**100.99%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**99.06%**	**63.79%**	**100.00%**	**89.44%**	**115.89%**	**116.14%**		**122.45%**	**116.76%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

SUMMARY OF RESULTS	RESIDENTIAL						
	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Basic (0-600kW)	R-Basic (601-999 kW)	R-Basic (1000+ kW)	R-TOU & R-Solar TOU	R-Demand & R-Solar (Demand)
DEVELOPMENT OF RATE BASE							
PRODUCTION PLANT IN SERVICE	$ 488,801,299	$ 13,765,408	$ 729,443,030	$ 333,238,314	$ 132,175,064	$ 1,729,124,395	$ 2,218,251,813
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	427,762,293	10,724,735	1,113,504,688	373,356,538	118,752,094	1,745,234,085	1,982,041,202
GENERAL & INTANGIBLE PLANT	109,156,454	2,816,987	278,467,494	92,327,987	30,618,593	431,305,957	508,611,251
LESS: RESERVE FOR DEPRECIATION	(379,654,765)	(10,202,046)	(764,140,288)	(291,241,266)	(104,239,278)	(1,432,513,813)	(1,743,942,386)
MATERIALS, SUPPLIES & PREPAYMENTS	26,739,791	743,388	51,312,979	19,786,828	7,389,155	99,853,789	124,482,573
MISCELLANEOUS DEFERRED DEBITS	1,339,970	36,863	2,880,052	1,031,507	374,707	5,087,722	6,293,268
OTHER DEFERRED CREDITS	(61,948,660)	(1,754,410)	(98,592,720)	(42,789,137)	(16,895,238)	(221,673,385)	(284,260,015)
OPEB	25,859,221	673,719	63,508,712	21,481,611	7,233,324	101,273,502	120,325,050
WORKING CASH	(4,536,575)	(116,559)	(9,451,920)	(3,624,723)	(1,229,536)	(17,436,894)	(20,461,022)
REGULATORY ASSETS	(44,639,510)	(1,214,710)	(82,797,897)	(33,225,316)	(12,177,874)	(166,534,033)	(204,437,254)
ACCUM. DEFERRED TAXES	(122,483,951)	(3,256,157)	(254,697,399)	(95,687,809)	(33,621,425)	(467,518,070)	(562,470,536)
OPERATING LEASES	1,138,283	22,664	4,205,551	1,230,754	317,700	5,006,809	5,066,715
DECOMMISSIONING FUND	70,243,803	1,984,461	105,045,499	47,806,061	19,021,321	248,581,909	319,492,144
CUSTOMER ADVANCES	(1,941,352)	(100,878)	(8,858,012)	(3,752,413)	(1,696,196)	(19,668,272)	(23,654,098)
CUSTOMER DEPOSITS	(351,849)	(18,477)	(1,630,471)	(690,312)	(312,342)	(3,618,504)	(4,349,415)
PROFORMA ADJUSTMENTS	28,397,420	775,078	53,304,189	21,095,894	7,776,847	105,209,441	130,229,037
TOTAL RATE BASE	**563,881,873**	**14,880,066**	**1,181,503,488**	**440,344,517**	**153,486,917**	**2,141,714,639**	**2,571,218,327**
DEVELOPMENT OF RETURN							
BASE REVENUES FROM RATES	58,452,741	3,069,538	270,870,328	114,681,673	51,889,334	601,142,428	722,568,841
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	8,763,675	(3,471,297)	1,613,889	(18,297,562)	8,537,194
SURCHARGE & OTHER ELECTRIC REVENUES	15,307,364	514,359	39,309,902	15,148,017	6,130,360	77,175,703	102,098,257
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(4,302,104)	(182,825)	(22,282,606)	(7,959,670)	(3,066,291)	(37,903,757)	(49,694,867)
TOTAL OPERATING REVENUES	**69,001,173**	**3,346,404**	**296,661,299**	**118,398,723**	**56,567,292**	**622,116,812**	**783,509,425**
OPERATING EXPENSES							
OPERATION & MAINTENANCE	50,406,025	1,749,933	186,056,505	71,820,650	28,887,368	383,628,315	485,455,100
ADMINISTRATIVE & GENERAL	7,520,578	195,105	18,705,855	6,289,912	2,104,691	29,553,299	34,992,084
DEPRECIATION & AMORT EXPENSE	30,489,298	813,363	63,872,121	23,791,468	8,392,892	116,120,458	140,331,694
OTHER EXPENSE ITEMS	1,306,999	36,924	1,954,544	889,508	353,923	4,625,269	5,944,678
TAXES OTHER THAN INCOME	9,926,018	260,540	21,769,882	7,957,452	2,730,526	38,509,934	45,679,445
PROFORMA ADJUSTMENTS	14,602,470	426,680	17,175,327	5,734,260	3,285,072	34,896,467	56,807,042
INCOME TAX	(10,646,375)	17,732	(4,299,673)	1,425,617	2,685,800	10,068,419	8,346,323
PROFORMA INCOME TAX ADJUSTMENTS	(4,735,333)	(162,873)	(7,475,604)	(4,201,770)	(1,157,242)	(22,318,332)	(23,984,146)
TOTAL OPERATING EXPENSES	**98,869,679**	**3,337,405**	**297,758,959**	**113,707,095**	**47,283,030**	**595,083,829**	**753,572,220**
OPERATING INCOME	**(29,868,506)**	**8,999**	**(1,097,660)**	**4,691,627**	**9,284,262**	**27,032,982**	**29,937,205**
RATE OF RETURN (PRESENT)	**-5.30%**	**0.06%**	**-0.09%**	**1.07%**	**6.05%**	**1.26%**	**1.16%**
INDEX RATE OF RETURN (PRESENT)	**(1.8)**	**0.0**	**(0.0)**	**0.4**	**2.0**	**0.4**	**0.4**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**156,307,569**	**4,544,814**	**403,415,266**	**150,538,939**	**57,001,143**	**768,555,528**	**957,494,075**
% OF TOTAL COST OF SERVICE (PRESENT)	**37.73%**	**68.04%**	**70.44%**	**75.08%**	**95.25%**	**77.06%**	**77.83%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**45.56%**	**81.45%**	**85.12%**	**90.72%**	**115.26%**	**93.12%**	**93.76%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

SUMMARY OF RESULTS	GENERAL SERVICE								
	E-20 (Church Rate)	E-32 TOU (0-20 kW)	E-32 TOU (21-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-20 kW)	E-32 (21-100 kW)	E-32 (101-400 kW)
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 12,160,381	$ 5,579,743	$ 8,269,436	$ 30,602,927	$ 77,074,903	$ 53,274,445	$ 512,732,873	$ 795,188,536	$ 914,636,571
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	10,547,706	3,928,185	3,861,969	11,002,846	25,819,833	31,984,511	497,065,199	384,921,647	342,574,123
GENERAL & INTANGIBLE PLANT	2,445,496	1,214,554	1,469,386	4,792,058	11,769,093	8,672,309	134,584,485	146,015,666	140,898,091
LESS: RESERVE FOR DEPRECIATION	(9,260,148)	(4,104,653)	(5,343,821)	(18,588,426)	(46,047,273)	(35,767,346)	(425,372,911)	(518,926,029)	(554,997,907)
MATERIALS, SUPPLIES & PREPAYMENTS	672,766	332,228	434,043	1,617,636	3,951,065	2,866,356	31,302,821	40,606,126	45,650,594
MISCELLANEOUS DEFERRED DEBITS	32,668	17,402	22,573	82,749	201,571	137,750	1,656,371	2,129,779	2,302,222
OTHER DEFERRED CREDITS	(1,550,039)	(756,154)	(1,083,437)	(4,075,355)	(10,148,279)	(6,928,098)	(68,177,331)	(102,640,818)	(118,319,355)
OPEB	602,126	289,809	362,935	1,190,276	2,925,795	2,152,613	31,489,704	36,000,089	34,968,476
WORKING CASH	(111,203)	(37,811)	(46,341)	(138,153)	(349,419)	(361,739)	(4,672,280)	(4,762,256)	(4,709,748)
REGULATORY ASSETS	(1,123,463)	(479,000)	(626,526)	(2,231,525)	(5,518,937)	(4,438,012)	(48,569,682)	(60,059,151)	(66,559,654)
ACCUM. DEFERRED TAXES	(3,020,346)	(1,273,263)	(1,602,860)	(5,447,087)	(13,437,246)	(11,191,450)	(136,604,844)	(156,227,494)	(164,192,403)
OPERATING LEASES	21,251	3,935	2,345	(23,813)	(51,285)	587	1,274,737	631,860	(217,911)
DECOMMISSIONING FUND	1,752,220	816,547	1,204,013	4,484,015	11,264,979	7,747,836	74,342,056	115,275,494	133,048,734
CUSTOMER ADVANCES	(505,673)	(380,282)	(503,612)	(1,333,752)	(3,444,317)	(2,425,196)	(31,915,380)	(40,834,324)	(44,067,912)
CUSTOMER DEPOSITS	(73,495)	(55,316)	(73,245)	(193,861)	(500,661)	(352,540)	(4,641,920)	(5,937,292)	(6,406,665)
PROFORMA ADJUSTMENTS	694,802	317,780	432,230	1,540,647	3,835,158	2,811,882	31,538,290	41,785,723	45,728,213
TOTAL RATE BASE	**13,285,049**	**5,413,704**	**6,779,087**	**23,281,182**	**57,344,978**	**48,183,908**	**596,032,187**	**673,167,555**	**700,335,468**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,958,051	2,979,043	3,944,581	10,440,351	26,962,992	18,985,953	249,989,443	319,751,351	345,029,300
PRO FORMA TO BASE REVENUES FROM RATES	(51,315)	64,393	(248,666)	(524,002)	2,512,750	(240,838)	(3,267,610)	(3,615,921)	(4,925,494)
SURCHARGE & OTHER ELECTRIC REVENUES	563,836	385,003	474,487	1,507,987	3,447,597	2,673,587	30,357,537	43,080,394	45,613,844
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(271,375)	(212,394)	(236,290)	(526,766)	(1,110,721)	(1,162,244)	(16,682,851)	(21,841,740)	(19,790,485)
TOTAL OPERATING REVENUES	**4,199,197**	**3,216,044**	**3,934,112**	**10,897,569**	**31,812,618**	**20,256,458**	**260,396,519**	**337,374,083**	**365,927,166**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,882,082	1,561,672	2,030,311	7,443,789	18,081,818	13,597,127	132,496,905	190,870,127	212,800,995
ADMINISTRATIVE & GENERAL	174,646	83,505	103,866	337,248	828,760	615,551	9,168,890	10,337,005	9,939,782
DEPRECIATION & AMORT EXPENSE	743,035	327,566	418,768	1,436,225	3,546,477	2,804,897	34,534,062	40,787,325	42,860,244
OTHER EXPENSE ITEMS	32,603	15,193	22,403	83,434	209,606	144,162	1,383,264	2,144,901	2,475,610
TAXES OTHER THAN INCOME	245,808	100,119	119,412	395,307	966,477	872,680	11,153,375	11,654,488	11,964,822
PROFORMA ADJUSTMENTS	280,829	71,413	64,546	776,497	3,162,866	1,913,376	7,406,075	13,225,635	20,597,937
INCOME TAX	7,733	273,258	373,265	373,669	1,223,904	518,320	18,088,314	21,260,407	21,834,405
PROFORMA INCOME TAX ADJUSTMENTS	(147,909)	(53,794)	(135,396)	(450,293)	(431,935)	(815,547)	(6,708,113)	(9,520,283)	(11,157,074)
TOTAL OPERATING EXPENSES	**4,218,827**	**2,378,933**	**2,997,175**	**10,395,874**	**27,587,971**	**19,650,566**	**207,522,773**	**280,759,606**	**311,316,723**
OPERATING INCOME	**(19,630)**	**837,112**	**936,938**	**501,695**	**4,224,647**	**605,893**	**52,873,746**	**56,614,477**	**54,610,443**
RATE OF RETURN (PRESENT)	**-0.15%**	**15.46%**	**13.82%**	**2.15%**	**7.37%**	**1.26%**	**8.87%**	**8.41%**	**7.80%**
INDEX RATE OF RETURN (PRESENT)	**(0.0)**	**5.1**	**4.6**	**0.7**	**2.4**	**0.4**	**2.9**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,309,556**	**2,486,970**	**3,148,017**	**11,665,247**	**29,790,044**	**22,935,047**	**237,863,709**	**310,350,664**	**339,869,498**
% OF TOTAL COST OF SERVICE (PRESENT)	**75.64%**	**122.56%**	**117.97%**	**85.46%**	**98.04%**	**84.19%**	**104.59%**	**102.99%**	**100.89%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**91.06%**	**151.44%**	**145.29%**	**105.22%**	**122.58%**	**101.48%**	**128.36%**	**126.06%**	**124.03%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

SUMMARY OF RESULTS	GENERAL SERVICE E-32 (401+ kW)	E-34	E-35	AG-X
DEVELOPMENT OF RATE BASE				
PRODUCTION PLANT IN SERVICE	$ 742,288,876	$ 165,390,653	$ 509,157,006	$ 255,681,872
TRANSMISSION PLANT IN SERVICE	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	249,726,692	43,002,737	114,822,244	63,289,617
GENERAL & INTANGIBLE PLANT	112,720,666	24,744,695	76,652,908	38,087,866
LESS: RESERVE FOR DEPRECIATION	(443,091,368)	(95,361,908)	(289,804,980)	(146,606,994)
MATERIALS, SUPPLIES & PREPAYMENTS	37,759,747	8,395,890	26,129,012	12,990,218
MISCELLANEOUS DEFERRED DEBITS	1,920,565	435,534	1,374,309	675,474
OTHER DEFERRED CREDITS	(97,362,086)	(21,895,160)	(68,060,087)	(33,916,454)
OPEB	28,019,416	6,153,148	19,061,616	9,469,902
WORKING CASH	(3,424,888)	(638,631)	(1,740,757)	(953,668)
REGULATORY ASSETS	(53,150,663)	(11,312,539)	(34,111,854)	(17,366,848)
ACCUM. DEFERRED TAXES	(129,472,511)	(27,162,737)	(81,388,376)	(41,560,163)
OPERATING LEASES	(453,703)	(150,147)	(558,969)	(249,997)
DECOMMISSIONING FUND	108,391,564	24,219,412	74,749,071	37,464,644
CUSTOMER ADVANCES	(33,111,143)	(4,891,691)	(71,283,271)	(10,302,194)
CUSTOMER DEPOSITS	(4,812,982)	(710,299)	(2,857,985)	(1,497,169)
PROFORMA ADJUSTMENTS	36,877,857	8,090,630	24,817,250	12,471,504
TOTAL RATE BASE	**552,826,039**	**118,309,588**	**296,957,137**	**177,677,609**
DEVELOPMENT OF RETURN				
BASE REVENUES FROM RATES	259,201,950	38,252,968	153,916,079	80,629,651
PRO FORMA TO BASE REVENUES FROM RATES	304,925	2,210,724	(5,836,221)	(1,342,165)
SURCHARGE & OTHER ELECTRIC REVENUES	33,914,431	7,477,244	24,217,213	5,158,094
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(11,674,669)	(2,299,744)	(7,790,126)	2,809,278
TOTAL OPERATING REVENUES	**281,746,637**	**45,641,193**	**164,506,945**	**87,254,858**
OPERATING EXPENSES				
OPERATION & MAINTENANCE	174,962,433	40,524,545	127,343,842	68,489,878
ADMINISTRATIVE & GENERAL	7,938,614	1,737,196	5,372,885	2,671,500
DEPRECIATION & AMORT EXPENSE	34,114,284	7,299,435	22,144,386	11,209,505
OTHER EXPENSE ITEMS	2,016,825	450,648	1,390,850	697,101
TAXES OTHER THAN INCOME	9,318,267	1,895,042	5,587,087	2,884,186
PROFORMA ADJUSTMENTS	19,572,255	6,536,884	13,110,803	4,742,134
INCOME TAX	11,657,985	(2,451,006)	1,523,237	(1,439,545)
PROFORMA INCOME TAX ADJUSTMENTS	(7,616,253)	(1,632,430)	(6,595,338)	(801,544)
TOTAL OPERATING EXPENSES	**251,964,411**	**54,360,314**	**169,877,751**	**88,453,215**
OPERATING INCOME	**29,782,226**	**(8,719,121)**	**(5,370,807)**	**(1,198,358)**
RATE OF RETURN (PRESENT)	**5.39%**	**-7.37%**	**-1.81%**	**-0.67%**
INDEX RATE OF RETURN (PRESENT)	**1.8**	**(2.4)**	**(0.6)**	**(0.2)**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**277,152,418**	**64,408,170**	**186,169,924**	**99,360,135**
% OF TOTAL COST OF SERVICE (PRESENT)	**92.91%**	**62.61%**	**78.82%**	**78.05%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**117.75%**	**92.28%**	**94.31%**	**79.15%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

SUMMARY OF RESULTS	ELECTRIC TOTAL	ALL OTHER	ACC JURISDICTION	RETAIL					
				RESIDENTIAL	GENERAL SERVICE	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 9,832,767,730	$ 12,364,736	$ 9,820,402,994	$ 5,521,584,142	$ 4,202,486,962	$ 74,902,778	$ -	$ 18,298,275	$ 3,130,837
TRANSMISSION PLANT IN SERVICE	3,414,532,481	3,414,532,481	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	7,763,311,806	47,825	7,763,263,981	5,719,435,080	1,832,558,568	40,475,684	-	107,962,247	62,832,403
GENERAL & INTANGIBLE PLANT	2,381,362,366	201,428,361	2,179,934,005	1,435,352,192	721,558,037	13,717,912	-	5,257,062	4,048,802
LESS: RESERVE FOR DEPRECIATION	(8,525,604,548)	(1,097,524,168)	(7,428,080,380)	(4,650,595,293)	(2,666,669,062)	(50,390,115)	-	(39,862,397)	(20,563,514)
MATERIALS, SUPPLIES & PREPAYMENTS	611,970,887	60,482,273	551,488,614	324,375,100	218,469,492	4,329,734	-	2,987,944	1,326,344
MISCELLANEOUS DEFERRED DEBITS	30,089,000	1,720,840	28,368,160	16,757,262	11,267,525	223,564	-	83,378	36,430
OTHER DEFERRED CREDITS	(1,293,452,000)	(17,036,265)	(1,276,415,735)	(712,347,034)	(550,097,775)	(10,193,799)	-	(3,051,368)	(725,761)
OPEB	568,515,119	50,051,519	518,463,600	335,891,056	177,035,092	3,391,955	-	1,282,391	863,107
WORKING CASH	(105,488,059)	(25,065,875)	(80,422,184)	(56,126,168)	(22,660,505)	(410,199)	-	(780,305)	(445,007)
REGULATORY ASSETS	(824,250,000)	41,483,766	(865,733,766)	(535,794,821)	(314,528,745)	(6,020,048)	-	(6,300,972)	(3,089,181)
ACCUM. DEFERRED TAXES	(2,354,271,572)	(1,458,100)	(2,352,813,472)	(1,516,965,747)	(794,735,268)	(15,300,861)	-	(16,845,061)	(8,966,536)
OPERATING LEASES	22,468,854	5,215,753	17,253,101	16,988,465	232,254	(25,403)	-	(7,784)	65,570
DECOMMISSIONING FUND	1,422,493,893	1,706,993	1,420,786,900	794,349,143	612,181,027	11,005,649	-	2,774,412	476,669
CUSTOMER ADVANCES	(336,198,398)	(30,943,932)	(305,254,466)	(59,660,044)	(245,009,669)	(12,453)	-	(572,001)	(299)
CUSTOMER DEPOSITS	(40,062,749)	-	(40,062,749)	(10,971,370)	(28,113,431)	(604,946)	-	(373,003)	-
PROFORMA ADJUSTMENTS	578,176,449	13,488,880	564,687,569	340,656,005	216,923,057	4,027,681	-	2,107,725	973,101
TOTAL RATE BASE	**13,146,361,258**	**2,630,495,087**	**10,515,866,171**	**6,962,927,970**	**3,370,897,558**	**69,117,133**	**-**	**72,960,544**	**39,962,966**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,468,594,702	70,581,514	3,398,013,188	1,822,674,883	1,514,041,713	32,579,215	-	20,087,962	8,629,415
PRO FORMA TO BASE REVENUES FROM RATES	(21,200,909)	-	(21,200,909)	(3,365,597)	(14,959,440)	(2,243,274)	-	(790,435)	157,837
SURCHARGE & OTHER ELECTRIC REVENUES	513,230,298	51,966,910	461,263,388	252,347,800	202,112,352	4,971,078	-	1,455,998	376,160
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(209,593,326)	(181,152)	(209,412,174)	(125,386,522)	(80,795,562)	(2,446,406)	-	(569,097)	(214,587)
TOTAL OPERATING REVENUES	**3,751,030,765**	**122,367,272**	**3,628,663,493**	**1,946,270,563**	**1,620,399,063**	**32,860,613**	**-**	**20,184,428**	**8,948,826**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,021,289,826	(210,113,145)	2,231,402,972	1,237,621,354	964,114,018	21,429,976	-	6,394,373	1,843,251
ADMINISTRATIVE & GENERAL	169,603,050	19,345,717	150,257,333	98,091,050	50,547,234	968,902	-	385,233	264,914
DEPRECIATION & AMORT EXPENSE	677,267,319	82,201,254	595,066,064	377,999,320	207,884,765	3,971,213	-	3,403,723	1,807,044
OTHER EXPENSE ITEMS	26,436,176	2	26,436,174	14,780,161	11,390,738	204,781	-	51,625	8,870
TAXES OTHER THAN INCOME	227,125,941	39,350,683	187,775,259	125,142,412	58,799,043	1,167,153	-	1,723,250	943,400
PROFORMA ADJUSTMENTS	231,114,792	4,280,481	226,834,312	128,346,672	95,907,799	1,477,139	-	827,441	275,261
INCOME TAX	115,485,000	30,346,870	85,138,130	2,501,082	78,239,201	1,897,174	-	1,789,433	711,239
PROFORMA INCOME TAX ADJUSTMENTS	(113,749,921)	(1,563,439)	(112,186,482)	(62,909,052)	(47,159,522)	(1,519,689)	-	(524,885)	(73,334)
TOTAL OPERATING EXPENSES	**3,354,572,184**	**(36,151,578)**	**3,390,723,762**	**1,921,572,999**	**1,419,723,277**	**29,596,651**	**-**	**14,050,193**	**5,780,643**
OPERATING INCOME	**396,458,581**	**158,518,851**	**237,939,731**	**24,697,565**	**200,675,786**	**3,263,962**	**0**	**6,134,235**	**3,168,182**
RATE OF RETURN (PRESENT)	**3.02%**	**6.03%**	**2.26%**	**0.35%**	**5.95%**	**4.72%**	**0.00%**	**8.41%**	**7.93%**
INDEX RATE OF RETURN (PRESENT)	**1.0**	**2.0**	**0.8**	**0.1**	**2.0**	**1.6**	**-**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**4,259,739,214**	**110,774,692**	**4,148,964,522**	**2,507,485,245**	**1,580,985,055**	**33,152,163**	**0**	**18,655,191**	**8,686,868**
% OF TOTAL COST OF SERVICE (PRESENT)	**81.78%**	**63.72%**	**82.26%**	**73.82%**	**95.05%**	**94.50%**	**0.00%**	**103.04%**	**101.06%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**99.06%**	**63.72%**	**100.00%**	**89.09%**	**116.59%**	**116.75%**		**122.73%**	**116.85%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

SUMMARY OF RESULTS	RESIDENTIAL								
	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar TOU	R-Solar (Demand)	R-Basic (0-600kW)	R-Basic (601-999 kW)	R-Basic (1000+ kW)	R-TOU	R-Demand
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 348,065,578	$ 10,945,080	$ 140,579,287	$ 61,736,033	$ 750,935,014	$ 343,052,008	$ 136,069,080	$ 1,546,433,722	$ 2,183,768,340
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	351,606,923	9,356,015	190,179,895	70,245,163	1,126,978,503	379,712,656	121,111,058	1,538,043,823	1,932,201,045
GENERAL & INTANGIBLE PLANT	88,586,689	2,391,266	45,805,712	17,356,656	281,583,031	93,737,361	31,179,718	379,503,782	495,207,979
LESS: RESERVE FOR DEPRECIATION	(289,412,899)	(8,415,583)	(136,046,970)	(54,589,997)	(778,347,284)	(297,759,174)	(106,788,130)	(1,271,061,473)	(1,708,173,783)
MATERIALS, SUPPLIES & PREPAYMENTS	19,977,652	598,345	9,316,222	3,867,851	52,324,332	20,238,019	7,569,975	88,598,259	121,884,445
MISCELLANEOUS DEFERRED DEBITS	1,027,393	29,865	499,207	202,566	2,924,874	1,051,144	382,749	4,495,475	6,143,989
OTHER DEFERRED CREDITS	(44,486,220)	(1,390,155)	(18,683,566)	(8,151,234)	(101,200,903)	(43,963,656)	(17,366,355)	(197,763,242)	(279,341,704)
OPEB	20,744,109	567,842	10,553,014	4,042,771	64,283,445	21,832,065	7,372,854	89,229,563	117,265,393
WORKING CASH	(3,528,277)	(99,527)	(1,686,662)	(649,158)	(9,628,155)	(3,709,013)	(1,261,031)	(15,493,224)	(20,071,121)
REGULATORY ASSETS	(33,367,305)	(993,555)	(15,272,049)	(6,251,783)	(84,594,948)	(34,052,259)	(12,499,298)	(148,158,466)	(200,605,159)
ACCUM. DEFERRED TAXES	(94,270,881)	(2,709,479)	(45,243,342)	(17,904,320)	(259,243,320)	(97,788,265)	(34,433,858)	(414,608,072)	(550,764,209)
OPERATING LEASES	1,078,748	23,411	626,946	200,078	4,223,959	1,241,470	321,134	4,369,409	4,903,311
DECOMMISSIONING FUND	49,981,383	1,574,429	20,253,727	8,916,535	108,122,733	49,206,576	19,578,542	222,260,149	314,455,070
CUSTOMER ADVANCES	(1,928,648)	(100,621)	(1,861,534)	(800,657)	(8,859,941)	(3,753,291)	(1,696,546)	(17,802,934)	(22,855,873)
CUSTOMER DEPOSITS	(351,849)	(18,477)	(342,859)	(147,442)	(1,630,471)	(690,312)	(312,342)	(3,275,644)	(4,201,973)
PROFORMA ADJUSTMENTS	21,250,522	631,376	9,618,834	3,953,177	54,407,289	21,599,407	7,975,577	93,518,547	127,701,276
TOTAL RATE BASE	**434,972,919**	**12,390,233**	**208,295,861**	**82,026,239**	**1,202,278,157**	**449,954,735**	**157,203,128**	**1,898,289,672**	**2,517,517,025**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557	270,870,328	114,681,673	51,889,334	544,183,153	698,074,284
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,216)	(494,918)	8,763,675	(3,471,297)	1,613,889	(17,040,346)	9,032,112
SURCHARGE & OTHER ELECTRIC REVENUES	11,844,763	429,336	7,022,580	3,196,258	39,778,749	15,345,946	6,214,637	69,089,059	99,426,471
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(4,296,386)	(182,683)	(3,706,507)	(1,674,857)	(22,283,362)	(7,959,984)	(3,066,425)	(34,195,505)	(48,020,813)
TOTAL OPERATING REVENUES	**65,544,291**	**3,261,523**	**59,018,132**	**25,521,040**	**297,129,390**	**118,596,338**	**56,651,434**	**562,036,362**	**758,512,053**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	87,941,091	2,574,744	82,300,484	32,395,231	179,526,824	68,654,486	27,316,415	311,251,523	445,660,557
ADMINISTRATIVE & GENERAL	6,057,758	164,972	3,098,984	1,181,854	18,928,342	6,390,737	2,144,751	26,029,608	34,094,045
DEPRECIATION & AMORT EXPENSE	23,480,639	674,724	11,254,945	4,465,553	64,979,736	24,299,827	8,591,322	102,910,744	137,341,831
OTHER EXPENSE ITEMS	929,984	29,295	376,854	165,907	2,011,801	915,566	364,291	4,135,509	5,850,953
TAXES OTHER THAN INCOME	7,753,267	219,092	3,839,090	1,493,079	22,127,749	8,123,598	2,794,146	34,104,891	44,687,500
PROFORMA ADJUSTMENTS	9,595,986	309,606	2,890,090	1,425,556	17,894,006	6,044,236	3,414,114	30,525,355	56,247,722
INCOME TAX	(17,066,801)	(134,184)	(10,668,554)	(3,583,631)	(3,160,615)	1,985,343	2,989,202	19,045,939	13,094,384
PROFORMA INCOME TAX ADJUSTMENTS	(3,507,200)	(134,087)	(1,921,111)	(880,984)	(7,651,530)	(4,277,561)	(1,188,838)	(20,033,152)	(23,314,588)
TOTAL OPERATING EXPENSES	**115,184,724**	**3,704,160**	**91,170,783**	**36,662,564**	**294,656,311**	**112,136,231**	**46,425,403**	**507,970,417**	**713,662,405**
OPERATING INCOME	**(49,640,433)**	**(442,637)**	**(32,152,651)**	**(11,141,524)**	**2,473,079**	**6,460,107**	**10,226,031**	**54,065,945**	**44,849,648**
RATE OF RETURN (PRESENT)	**-11.41%**	**-3.57%**	**-15.44%**	**-13.58%**	**0.21%**	**1.44%**	**6.50%**	**2.85%**	**1.78%**
INDEX RATE OF RETURN (PRESENT)	**(3.8)**	**(1.2)**	**(5.1)**	**(4.5)**	**0.1**	**0.5**	**2.2**	**0.9**	**0.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**169,356,549**	**4,889,790**	**120,221,742**	**47,379,749**	**400,797,662**	**149,171,911**	**56,128,090**	**651,529,864**	**908,009,888**
% OF TOTAL COST OF SERVICE (PRESENT)	**34.82%**	**63.24%**	**47.04%**	**51.92%**	**70.90%**	**75.77%**	**96.73%**	**82.22%**	**79.36%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**42.05%**	**75.71%**	**56.41%**	**64.23%**	**85.67%**	**91.55%**	**117.05%**	**99.44%**	**95.52%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

SUMMARY OF RESULTS	GENERAL SERVICE								
	E-20 (Church Rate)	E-32 TOU (0-20 kW)	E-32 TOU (21-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-20 kW)	E-32 (21-100 kW)	E-32 (101-400 kW)
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 12,518,695	$ 5,744,476	$ 8,513,420	$ 31,506,572	$ 79,350,051	$ 54,846,047	$ 527,852,748	$ 818,637,166	$ 941,619,232
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	10,872,863	4,005,357	3,977,722	11,378,234	26,737,199	33,061,852	504,689,085	396,096,313	354,053,833
GENERAL & INTANGIBLE PLANT	2,500,600	1,239,125	1,505,128	4,926,093	12,102,848	8,911,504	136,777,449	149,396,876	144,799,265
LESS: RESERVE FOR DEPRECIATION	(9,525,163)	(4,207,993)	(5,496,415)	(19,142,658)	(47,431,000)	(36,842,017)	(434,911,496)	(533,534,718)	(571,486,450)
MATERIALS, SUPPLIES & PREPAYMENTS	691,461	340,537	445,897	1,662,807	4,062,131	2,947,813	32,021,164	41,707,340	46,929,229
MISCELLANEOUS DEFERRED DEBITS	33,446	17,802	23,136	84,961	206,999	141,421	1,689,891	2,181,517	2,363,635
OTHER DEFERRED CREDITS	(1,593,939)	(777,283)	(1,114,160)	(4,191,628)	(10,438,312)	(7,126,227)	(70,053,616)	(105,546,787)	(121,701,753)
OPEB	615,833	295,919	371,823	1,223,608	3,008,788	2,212,106	32,035,007	36,840,835	35,938,512
WORKING CASH	(114,858)	(38,805)	(47,903)	(143,186)	(362,249)	(374,320)	(4,776,316)	(4,919,134)	(4,874,387)
REGULATORY ASSETS	(1,158,209)	(491,763)	(645,391)	(2,299,351)	(5,687,874)	(4,575,113)	(49,754,724)	(61,865,672)	(68,580,967)
ACCUM. DEFERRED TAXES	(3,109,679)	(1,304,797)	(1,649,665)	(5,613,708)	(13,852,613)	(11,537,437)	(139,561,165)	(160,724,877)	(169,189,144)
OPERATING LEASES	21,627	3,905	2,373	(24,078)	(51,641)	1,129	1,280,378	640,382	(214,478)
DECOMMISSIONING FUND	1,803,549	840,462	1,239,278	4,615,342	11,594,915	7,974,774	76,519,660	118,652,116	136,945,791
CUSTOMER ADVANCES	(505,705)	(380,297)	(503,634)	(1,333,834)	(3,444,524)	(2,425,338)	(31,916,745)	(40,836,441)	(44,070,356)
CUSTOMER DEPOSITS	(73,495)	(55,316)	(73,245)	(193,861)	(500,661)	(352,540)	(4,641,920)	(5,937,292)	(6,406,665)
PROFORMA ADJUSTMENTS	714,409	326,116	444,503	1,585,891	3,948,342	2,894,768	32,299,647	42,958,567	47,068,130
TOTAL RATE BASE	**13,691,437**	**5,557,447**	**6,992,868**	**24,041,201**	**59,242,398**	**49,758,421**	**609,549,046**	**693,746,190**	**723,193,429**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,958,051	2,979,043	3,944,581	10,440,351	26,962,992	18,985,953	249,989,443	319,751,351	345,029,300
PRO FORMA TO BASE REVENUES FROM RATES	(51,315)	64,393	(248,666)	(524,002)	2,512,750	(240,838)	(3,267,610)	(3,615,921)	(4,925,494)
SURCHARGE & OTHER ELECTRIC REVENUES	571,896	389,742	481,026	1,534,911	3,511,729	2,715,140	30,733,326	43,663,608	46,322,694
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(271,388)	(212,402)	(236,301)	(526,812)	(1,110,829)	(1,162,312)	(16,683,471)	(21,842,697)	(19,791,665)
TOTAL OPERATING REVENUES	**4,207,244**	**3,220,775**	**3,940,641**	**10,924,448**	**31,876,642**	**20,297,943**	**260,771,689**	**337,956,341**	**366,634,835**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,788,924	1,519,209	1,969,197	7,218,618	17,519,102	13,205,301	128,467,846	185,334,929	206,104,906
ADMINISTRATIVE & GENERAL	178,607	85,244	106,400	346,719	852,351	632,606	9,324,670	10,577,036	10,216,063
DEPRECIATION & AMORT EXPENSE	764,015	335,572	430,579	1,479,019	3,653,160	2,889,152	35,273,043	41,916,956	44,131,820
OTHER EXPENSE ITEMS	33,558	15,638	23,059	85,877	215,745	148,385	1,423,782	2,207,729	2,548,121
TAXES OTHER THAN INCOME	253,246	102,498	122,948	407,662	997,139	900,295	11,378,687	11,994,402	12,336,408
PROFORMA ADJUSTMENTS	293,359	78,156	73,974	814,346	3,254,005	1,974,445	7,957,978	14,079,668	21,620,414
INCOME TAX	21,382	280,715	383,765	413,572	1,323,002	580,414	18,786,568	22,176,915	22,997,222
PROFORMA INCOME TAX ADJUSTMENTS	(150,963)	(55,452)	(137,713)	(459,610)	(454,366)	(830,508)	(6,843,626)	(9,730,064)	(11,408,524)
TOTAL OPERATING EXPENSES	**4,182,127**	**2,361,580**	**2,972,209**	**10,306,203**	**27,360,138**	**19,500,089**	**205,768,949**	**278,557,571**	**308,546,430**
OPERATING INCOME	**25,117**	**859,195**	**968,431**	**618,244**	**4,516,504**	**797,854**	**55,002,740**	**59,398,771**	**58,088,406**
RATE OF RETURN (PRESENT)	**0.18%**	**15.46%**	**13.85%**	**2.57%**	**7.62%**	**1.60%**	**9.02%**	**8.56%**	**8.03%**
INDEX RATE OF RETURN (PRESENT)	**0.1**	**5.1**	**4.6**	**0.9**	**2.5**	**0.5**	**3.0**	**2.8**	**2.7**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,291,869**	**2,472,383**	**3,128,118**	**11,588,427**	**29,597,048**	**22,841,828**	**236,421,068**	**308,764,891**	**337,594,283**
% OF TOTAL COST OF SERVICE (PRESENT)	**75.89%**	**123.29%**	**118.72%**	**86.03%**	**98.68%**	**84.54%**	**105.23%**	**103.52%**	**101.57%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**91.36%**	**152.33%**	**146.21%**	**105.92%**	**123.38%**	**101.90%**	**129.14%**	**126.71%**	**124.87%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

SUMMARY OF RESULTS	GENERAL SERVICE E-32 (401+ kW)	E-34	E-35	AG-X
DEVELOPMENT OF RATE BASE				
PRODUCTION PLANT IN SERVICE	$ 764,197,724	$ 170,273,959	$ 524,195,173	$ 263,231,701
TRANSMISSION PLANT IN SERVICE	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	258,545,634	44,610,024	119,127,471	65,402,983
GENERAL & INTANGIBLE PLANT	115,922,665	25,455,798	78,844,529	39,176,156
LESS: RESERVE FOR DEPRECIATION	(456,397,919)	(98,237,165)	(298,505,388)	(150,950,681)
MATERIALS, SUPPLIES & PREPAYMENTS	38,821,360	8,631,592	26,858,292	13,349,871
MISCELLANEOUS DEFERRED DEBITS	1,972,341	447,320	1,411,362	693,693
OTHER DEFERRED CREDITS	(100,145,706)	(22,520,899)	(70,002,710)	(34,884,754)
OPEB	28,815,633	6,329,967	19,606,567	9,740,493
WORKING CASH	(3,549,596)	(662,943)	(1,808,524)	(988,282)
REGULATORY ASSETS	(54,775,059)	(11,658,758)	(35,150,775)	(17,885,091)
ACCUM. DEFERRED TAXES	(133,468,770)	(28,006,352)	(83,902,500)	(42,814,560)
OPERATING LEASES	(456,015)	(151,726)	(566,533)	(253,069)
DECOMMISSIONING FUND	111,566,245	24,928,749	76,938,246	38,561,898
CUSTOMER ADVANCES	(33,113,133)	(4,892,136)	(71,284,644)	(10,302,882)
CUSTOMER DEPOSITS	(4,812,982)	(710,299)	(2,857,985)	(1,497,169)
PROFORMA ADJUSTMENTS	37,966,117	8,329,959	25,549,353	12,837,256
TOTAL RATE BASE	**571,088,538**	**122,167,087**	**308,451,933**	**183,417,563**
DEVELOPMENT OF RETURN				
BASE REVENUES FROM RATES	259,201,950	38,252,968	153,916,079	80,629,651
PRO FORMA TO BASE REVENUES FROM RATES	304,925	2,210,724	(5,836,221)	(1,342,165)
SURCHARGE & OTHER ELECTRIC REVENUES	34,524,782	7,619,272	24,667,689	5,376,537
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(11,675,699)	(2,299,985)	(7,790,902)	2,808,901
TOTAL OPERATING REVENUES	**282,355,958**	**45,782,979**	**164,956,645**	**87,472,924**
OPERATING EXPENSES				
OPERATION & MAINTENANCE	169,467,819	39,302,123	123,619,687	67,596,357
ADMINISTRATIVE & GENERAL	8,165,000	1,787,332	5,527,109	2,748,099
DEPRECIATION & AMORT EXPENSE	35,139,893	7,520,015	22,810,092	11,541,449
OTHER EXPENSE ITEMS	2,075,896	463,846	1,431,584	717,517
TAXES OTHER THAN INCOME	9,613,186	1,955,628	5,764,492	2,972,454
PROFORMA ADJUSTMENTS	20,441,298	6,736,393	13,738,860	4,844,902
INCOME TAX	12,630,048	(2,228,439)	2,210,521	(1,336,485)
PROFORMA INCOME TAX ADJUSTMENTS	(7,830,124)	(1,681,593)	(6,750,219)	(826,761)
TOTAL OPERATING EXPENSES	**249,703,015**	**53,855,307**	**168,352,126**	**88,257,532**
OPERATING INCOME	**32,652,942**	**(8,072,328)**	**(3,395,481)**	**(784,608)**
RATE OF RETURN (PRESENT)	**5.72%**	**-6.61%**	**-1.10%**	**-0.43%**
INDEX RATE OF RETURN (PRESENT)	**1.9**	**(2.2)**	**(0.4)**	**(0.1)**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**275,212,402**	**63,944,565**	**184,724,784**	**99,403,388**
% OF TOTAL COST OF SERVICE (PRESENT)	**93.57%**	**63.07%**	**79.43%**	**78.02%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**118.58%**	**92.95%**	**95.05%**	**79.11%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

SUMMARY OF RESULTS	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
COS - Site Load	197,460,118	5,518,162	100,219,061	41,445,881
Solar Credits	41,152,549	973,348	(12,039,099)	(2,305,834)
Net COS	156,307,569	4,544,814	112,258,160	43,751,715
Revenue Deficiency	97,335,412	1,452,646	55,707,529	19,153,568
% COS Recovered	**37.7%**	**68.0%**	**50.4%**	**56.2%**
From COSS:				
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,217)	(494,918)
Credit for Adjustor Transfers				
DSMAC Transfer	605,657	28,629	523,755	242,769
EIS Transfer	161,153	7,667	140,842	65,040
LFCR	1,561,802	98,476	1,077,443	713,556
TEAM	(1,352,368)	(57,474)	(893,467)	(422,857)
Revenues	58,972,157	3,092,168	56,550,631	24,598,147

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Rates				
Weighted Non-Solar Residential ROR	1.41%	1.41%	1.41%	1.41%
Long Term Debt Rate	1.85%	1.85%	1.85%	1.85%
Composite Tax Rate	24.72%	24.72%	24.72%	24.72%
Total Rate Base				
Production				
Demand Production	298,016,226	8,419,272	138,510,454	59,339,658
Demand Production (Step-Up Txf Adj)	4,588,528	129,631	2,132,632	913,647
Total Production	302,604,754	8,548,903	140,643,086	60,253,305
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	35,745,588	973,113	14,992,162	6,637,949
Demand - OH Primary	32,378,255	798,995	16,442,792	6,329,265
Demand - OH Secondary	16,913,739	450,375	10,998,637	3,975,784
Demand - UG Primary	90,689,519	2,237,893	46,054,601	17,727,552
Demand - UG Secondary	15,335,459	408,341	9,972,173	3,604,722
Demand - OH Transformer	7,049,566	172,212	4,577,395	1,594,524
Demand - UG Transformer	26,987,495	656,011	17,521,993	6,091,091
Services - OH	3,352,407	69,227	2,171,301	707,179
Services - UG	12,074,515	249,334	7,820,358	2,547,030
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	240,526,543	6,015,502	130,551,411	49,215,095
Return on Rate Base				
Production				
Demand Production	4,192,771	118,450	1,948,694	834,846
Demand Production (Step-Up Txf Adj)	64,556	1,824	30,004	12,854
Total Production	4,257,326	120,274	1,978,698	847,700
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	502,902	13,691	210,924	93,389
Demand - OH Primary	455,528	11,241	231,333	89,046
Demand - OH Secondary	237,958	6,336	154,739	55,935
Demand - UG Primary	1,275,905	31,485	647,939	249,408
Demand - UG Secondary	215,754	5,745	140,298	50,715
Demand - OH Transformer	99,180	2,423	64,399	22,433
Demand - UG Transformer	379,685	9,229	246,516	85,695
Services - OH	47,165	974	30,548	9,949
Services - UG	169,876	3,508	110,024	35,834
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	3,383,952	84,632	1,836,719	692,404

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Taxes				
Production				
Demand Production	(433,622)	(12,250)	(201,537)	(86,341)
Demand Production (Step-Up Txf Adj)	(6,676)	(189)	(3,103)	(1,329)
Total Production	(440,298)	(12,439)	(204,640)	(87,670)
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	(52,011)	(1,416)	(21,814)	(9,658)
Demand - OH Primary	(47,111)	(1,163)	(23,925)	(9,209)
Demand - OH Secondary	(24,610)	(655)	(16,003)	(5,785)
Demand - UG Primary	(131,956)	(3,256)	(67,011)	(25,794)
Demand - UG Secondary	(22,314)	(594)	(14,510)	(5,245)
Demand - OH Transformer	(10,257)	(251)	(6,660)	(2,320)
Demand - UG Transformer	(39,268)	(955)	(25,495)	(8,863)
Services - OH	(4,878)	(101)	(3,159)	(1,029)
Services - UG	(17,569)	(363)	(11,379)	(3,706)
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	(349,973)	(8,753)	(189,956)	(71,609)
Expenses Excluding Income Taxes				
Production				
Demand Production	47,217,912	1,327,222	22,072,773	9,418,298
Demand Production (Step-Up Txf Adj)	381,178	10,769	177,162	75,899
Total Production	47,599,090	1,337,991	22,249,935	9,494,196
Transmission - Ancillary Services	16,156,943	430,852	7,367,571	3,015,966
Distribution				
Demand - Substation	3,425,111	94,192	1,447,108	642,211
Demand - OH Primary	3,688,662	91,951	1,887,014	728,048
Demand - OH Secondary	1,927,257	51,841	1,262,476	457,419
Demand - UG Primary	7,724,695	192,561	3,951,732	1,524,657
Demand - UG Secondary	1,266,689	34,072	829,761	300,638
Demand - OH Transformer	565,279	13,950	369,750	129,101
Demand - UG Transformer	2,164,028	53,139	1,415,381	493,167
Services - OH	383,711	8,004	250,352	81,727
Services - UG	1,002,851	20,920	654,310	213,599
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	22,148,283	560,630	12,067,884	4,570,567

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Revenue Credits				
Production				
Demand Production	223,112	6,677	105,768	47,364
Demand Production (Step-Up Txf Adj)	-	-	-	-
Total Production	223,112	6,677	105,768	47,364
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	904,775	24,882	382,267	169,646
Demand - OH Primary	991,565	24,718	507,256	195,710
Demand - OH Secondary	439,863	11,832	288,138	104,398
Demand - UG Primary	1,997,376	49,791	1,021,800	394,231
Demand - UG Secondary	337,753	9,085	221,250	80,163
Demand - OH Transformer	158,862	3,920	103,912	36,282
Demand - UG Transformer	608,165	14,934	397,770	138,597
Services - OH	87,404	1,823	57,027	18,616
Services - UG	266,644	5,562	173,972	56,793
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	5,792,408	146,547	3,153,392	1,194,435
Revenue Requirement				
Production				
Demand Production	50,753,949	1,426,745	23,714,163	10,119,439
Demand Production (Step-Up Txf Adj)	439,058	12,404	204,063	87,423
Total Production	51,193,007	1,439,149	23,918,226	10,206,862
Transmission - Ancillary Services	16,156,943	430,852	7,367,571	3,015,966
Distribution				
Demand - Substation	2,971,227	81,585	1,253,950	556,295
Demand - OH Primary	3,105,514	77,312	1,587,165	612,175
Demand - OH Secondary	1,700,742	45,690	1,113,073	403,171
Demand - UG Primary	6,871,268	170,999	3,510,860	1,354,040
Demand - UG Secondary	1,122,375	30,138	734,300	265,945
Demand - OH Transformer	495,339	12,202	323,577	112,932
Demand - UG Transformer	1,896,281	46,480	1,238,632	431,403
Services - OH	338,594	7,054	220,714	72,031
Services - UG	888,514	18,502	578,984	188,934
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	19,389,855	489,963	10,561,255	3,996,926
Percentage Difference in Delivery vs. Site				
Production Demand Credit (4CP & NCP)	21.54%	18.08%	28.32%	26.43%
Transmission Credit (4CP)	30.16%	25.30%	41.82%	39.92%
Distribution Substation Credit (NCP)	12.92%	10.86%	14.82%	12.93%
Distribution Primary Credit (NCP)	12.92%	10.86%	14.82%	12.93%
Distribution Secondary Credit (Ind Max)	11.92%	9.31%	14.04%	12.82%

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Solar Demand Credit				
Production				
Demand Production	10,931,371	257,918	6,715,542	2,674,292
Demand Production (Step-Up Txf Adj)	94,564	2,242	57,788	23,104
Total Production	11,025,935	260,160	6,773,330	2,697,396
Transmission - Ancillary Services (Before Adj.)	4,873,036	108,990	3,080,796	1,204,080
Transmission Cost Before Reallocation	5,408,118	248,522	4,574,090	2,132,554
Adjustment to Transmission Credit	(10,748,825)	(182,330)	(2,793,481)	(883,413)
Transmission - Ancillary Services (Incl. Adj.)	(5,875,789)	(73,340)	287,315	320,667
Distribution				
Demand - Substation	383,743	8,859	185,858	71,935
Demand - OH Primary	401,087	8,395	235,246	79,161
Demand - OH Secondary	202,695	4,256	156,308	51,667
Demand - UG Primary	887,446	18,568	520,371	175,091
Demand - UG Secondary	133,765	2,807	103,117	34,081
Demand - OH Transformer	59,035	1,136	45,440	14,472
Demand - UG Transformer	225,999	4,329	173,941	55,285
Services - OH	40,354	657	30,995	9,231
Services - UG	105,893	1,723	81,306	24,212
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	2,440,015	50,730	1,532,582	515,135
Value of Solar Production Less RCP	**33,562,387**	**735,797**	**(20,632,327)**	**(5,839,032)**
Total	**41,152,549**	**973,348**	**(12,039,099)**	**(2,305,834)**

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Costs
Delivered Load (Bottom-Up)

SUMMARY OF RESULTS	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
COS - Delivered Load	149,711,594	4,491,789	71,735,442	29,660,184
Solar Costs	19,644,955	398,001	48,486,299	17,719,564
Net COS	169,356,549	4,889,790	120,221,742	47,379,749
Revenue Deficiency	110,384,392	1,797,622	63,671,111	22,781,602
% COS Recovered	**34.8%**	**63.2%**	**47.0%**	**51.9%**
From COSS:				
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,217)	(494,918)
Credit for Adjustor Transfers				
DSMAC Transfer	605,657	28,629	523,755	242,769
EIS Transfer	161,153	7,667	140,842	65,040
LFCR	1,561,802	98,476	1,077,443	713,556
TEAM	(1,352,368)	(57,474)	(893,467)	(422,857)
Revenues	58,972,157	3,092,168	56,550,631	24,598,147

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Costs
Delivered Load (Bottom-Up)

Allocator	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Production Demand				
Back-up Costs				
4-CP (MW) Self-Supply	113.2	2.5	71.6	28.2
Capacity Value	40%	40%	40%	40%
Back-up Power Requirements (MW)	67.9	1.5	43.0	16.9
Cost per kW per month	10.34	10.34	10.34	10.34
COS	**8,427,507**	**186,175**	**5,337,007**	**2,097,568**
Reserves				
4-CP (MW) Self-Supply	113.2	2.5	71.6	28.2
Capacity Value	40%	40%	40%	40%
Firm portion of self-supply	45.3	1.0	28.6	11.3
Reserve margin	15%	15%	15%	15%
Required Reserves (MW)	6.8	0.2	4.3	1.7
Cost per kW per month	10.34	10.34	10.34	10.34
COS	**843,992**	**24,823**	**533,701**	**210,998**
Other Generator Services				
Solar Self-Supply MWh	401,245	10,130	224,200	97,315
Net metered MWh	474,571	9,071	-	-
Total applcable MWh	875,816	19,201	224,200	97,315
Cost per kWh	0.003	0.003	0.003	0.003
COS	**2,627,448**	**57,603**	**672,600**	**291,945**
Transmission				
Total 4CP allocator (MW)	7,299			
Trans Revenue Req - total retail	271,980,895			
line losses	9.21%			
4-CP (MW) - delivered load	262.2	7.6	99.6	42.4
at generator	286.3	7.6	99.6	42.4
transmission allocation %	3.92%	0.10%	1.36%	0.58%
transmission allocation $	10,669,471	283,179	3,711,142	1,579,843
	4,466,227	205,001	3,753,894	1,757,909
	6,203,245	**78,178**	**(42,753)**	**(178,066)**
Back-up Costs				
4-CP (MW) Self-Supply	113.2	2.5	71.6	28.2
Capacity Value	40%	40%	40%	40%
Back-up Power Requirements (MW)	67.9	1.5	43.0	16.9
Cost per kW per month	1.90	1.90	1.90	1.90
COS	**1,548,621**	**34,211**	**980,718**	**385,445**
Distribution Substation				
Self-Supply Back-up				
Summer NCP (MW) Self-Supply	44.8	1.1	24.5	9.2
Capacity Value	40%	40%	40%	40%
Back-up Grid Requirements (MW)	26.9	0.7	14.7	5.5
Cost per kW per month	0.92	0.92	0.92	0.92
COS	**295,850**	**7,699**	**161,673**	**60,490**

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Costs
Delivered Load (Bottom-Up)

Allocator	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Distribution Primary				
Self-Supply Back-up				
Summer NCP (MW) Self-Supply	44.8	1.1	24.5	9.2
Capacity Value	40%	40%	40%	40%
Back-up Grid Requirements (MW)	26.9	0.7	14.7	5.5
Cost per kW per month	3.60	3.60	3.60	3.60
COS	**1,161,715**	**30,231**	**634,841**	**237,525**
Distribution Secondary (Demand Classified)				
Site Load (Ind Max)				
Ind Max (MW) Self-Supply	71.2	1.5	44.5	16.4
Cost per kW per month	2.50	2.50	2.50	2.50
COS	**2,133,772**	**44,953**	**1,333,608**	**491,487**
Exports				
Export Grid Costs				
Annual Export MWh	474,571	9,071	366,080	134,303
Primary Grid cost per kWh	0.0259	0.0259	0.0259	0.0259
COS	**12,293,316**	**234,976**	**9,482,958**	**3,478,993**
Value of Exports	Site COSS			
Annual Export MWh	474,571	9,071	366,080	134,303
Value per kWh	(0.038321)	(0.038321)	(0.038321)	(0.038321)
Value	**(18,186,035)**	**(347,610)**	**(14,028,552)**	**(5,146,625)**
Cost of RCP Purchases				
RCP Purchases (MWh)	-	-	366,080	134,303
Average RCP rate per kWh	-	-	0.1186	0.1176
Value	**-**	**-**	**43,420,498**	**15,789,804**
Cost of EPR-6 Purchases				
EPR-6 Purchases (MWh)	79,293	1,615	-	-
Average rate per kWh	0.02895	0.02895	-	-
Value	**2,295,524**	**46,762**	**-**	**-**
Cost of Net Metering Exports	already reflected in the reduced revenue for the class			
Net Cost of Exports	**(3,597,195)**	**(65,872)**	**38,874,904**	**14,122,172**
Adjustments: revenue requirements additional to those reflected in the Delivered Load COS				
Production Demand	11,898,947	268,601	6,543,308	2,600,511
Transmission	7,751,866	112,389	937,965	207,379
Distribution Substation	295,850	7,699	161,673	60,490
Distribution Primary	1,161,715	30,231	634,841	237,525
Distribution Secondary (Demand Classified)	2,133,772	44,953	1,333,608	491,487
Net Cost of Exports	(3,597,195)	(65,872)	38,874,904	14,122,172
Total	**19,644,955**	**398,001**	**48,486,299**	**17,719,564**

Calculation of Fair Value Increment

(Thousands of Dollars)

Calculation of Fair Value Increment

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 6,315,975	48.07%	3.85%	1.85%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	6,822,261	51.93%	10.25%	5.32%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 13,138,236	100.00%		7.17%

	Capital Structure with 1.0% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 5,054,982	30.48%	3.85%	1.17%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	5,460,895	32.93%	10.25%	3.38%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	6,068,577	36.59%	1.00%	0.37%
11.	Total	$ 16,584,454	100.00%		4.92%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 16,584,454	$ 10,515,877
13.	Rate of Return	4.92%	7.17%
14.	Required Operating Income	$ 815,955	$ 753,988
15.	Adjusted Operating Income	237,851	$ 237,851
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 578,104	$ 516,137
17.	Revenue Conversion Factor	1.3359	1.3359
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 772,272	$ 689,492
19.	Fair Value Increment	$ 82,780	
	RCND Rate Base	$ 22,653,031	

DIRECT TESTIMONY OF ELIZABETH A. BLANKENSHIP

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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ATTACHMENT LIST

2019 Depreciation Rate Study Approved in Decision No. 78317 .... Attachment EAB-01DR

Proposed Nuclear Decommissioning Trust Funding Schedules ... Attachment EAB-02DR

DIRECT TESTIMONY OF ELIZABETH A. BLANKENSHIP
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-22-0144)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Elizabeth A. Blankenship. I am the Vice President, Controller and Chief Accounting Officer for Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West Capital Corporation (Pinnacle West). I am primarily responsible for overseeing the financial accounting and reporting functions of the Company and Pinnacle West. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Business with a major in Accounting from Arkansas State University in 1993. From 1993 to 2000, I was employed as an accountant for two companies in the long-term healthcare service industry. I joined APS in October 2000 as a Senior Accountant and during my 22 years at APS have worked in Accounting in various roles with increasing levels of responsibility.

Prior to my current position as the Vice President, Controller and Chief Accounting Officer, I was responsible for overseeing the accounting functions of the generation, transmission, distribution, customer service, and corporate resource areas, as well as the accounting systems and budget governance functions at Pinnacle West and APS as the Director of Accounting Operations. Prior to that position, I was responsible for the revenue and regulatory accounting, asset accounting, accounts receivable, and cash control functions at APS as the Manager of the Revenue/Regulatory Accounting Department. I am a Certified Public Accountant and a member of the Arizona Society of Certified Public Accountants.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony addresses the historical and forecasted accounting information and pro forma adjustments required by the Standard Filing Requirements (SFR) of the Arizona Corporation Commission (ACC or Commission) in support of the Company's rate case filing. I sponsor historical information for the 12-month period ended June 30, 2022 (Test Year), which was used as the Test Year in this proceeding, as well as any prior years and projected information presented as part of the following SFR Schedules:

- A-2 through A-5 – Summary Schedules
- B-1, B-3 through B-5 – Rate Base Schedules
- C-1 – Test Year Income Statements
- C-3 – Computation of Gross Revenue Conversion Factor
- D-1 through D-4 – Cost of Capital
- E-1 through E-9 – Financial Statements and Statistical Schedules
- F-1 through F-4 – Projections and Forecasts

APS witness Jamie Moe jurisdictionalizes the Total Company data to separate those items that fall within the Commission's regulatory jurisdiction from those that do not.

I will also provide direct testimony on certain pro forma adjustments made to the Test Year on SFR Schedules B-2 and C-2. Specifically, I will be sponsoring the "Total Company" column for the following pro formas on SFR Schedule B-2:

- Include West Phoenix Unit 4 Regulatory Disallowance
- Adjust Cash Working Capital for Cost of Service
- Include Cloud Computing

- Include Accumulated Deferred Income Taxes (ADIT) Impact from Navajo Generating Station (NGS) Amortization Disallowance
- Include Four Corners Selective Catalytic Reduction (SCR) Regulatory Disallowance
- Include E-3/E-4 Customer Bill Payment Fees Deferral

Additionally, I will be sponsoring the "Total Company" columns for the following pro formas on SFR Schedule C-2:

- Adjust for Post-Test Year Plant Additions
- Remove, Transfer and Annualize Test Year Surcharge Revenue and Expense
- Include West Phoenix Unit 4 Regulatory Disallowance
- Include Interest Expense on Customer Deposits
- Annualize E-3/E-4 Customer Bill Payment Fees Deferral Amortization
- Annualize Depreciation Expense – 2019 Approved Depreciation Rates
- Annualize Payroll Expense
- Normalize Employee Benefits
- Remove Supplemental Excess Benefit Retirement Plan Expense (SERP)
- Remove Stock Compensation
- Include Active Union Medical Trust Interest Income and Realized Gains
- Normalize Cash Incentive Expense
- Normalize Income Tax Expense/Interest Synchronization
- Annualize Property Tax Expense
- Annualize Property Tax Deferral Amortization
- Include Amortization of Property Tax Residual Deferral
- Annualize Four Corners Coal Reclamation Costs
- Annualize Navajo Coal Reclamation Costs

- Adjust Cash Working Capital for Cost of Service
- Normalize Nuclear Maintenance Expense
- Normalize Fossil Maintenance Expense
- Annualize Sundance Maintenance Expense Accrual
- Remove Navajo Power Plant Costs
- Include Navajo Regulatory Asset Amortization Disallowance
- Annualize Ocotillo Modernization Project (OMP) Deferral Amortization
- Include Amortization of OMP Residual Deferral
- Include OMP Deferral Equity Return Disallowance
- Adjust Four Corners SCR Depreciation Expense
- Annualize Four Corners SCR Deferral Amortization
- Include Amortization of Four Corners SCR Residual Deferral
- Annualize Cholla Inventory
- Annualize Four Corners Inventory
- Normalize Advertising Expense
- Include Removal Costs Associated with the West Phoenix Steam Units
- Remove Out of Period and Miscellaneous Items
- Amortize Cholla Unit 2 Regulatory Asset
- Annualize TEAM Balancing Account Amortization
- Include Amortization of TEAM Balancing Account Residual
- Amortize COVID Customer Relief Deferral

These adjustments are consistent with prior filings and represent "normalizations" and "annualizations" as discussed later in my testimony. These operating income pro formas are tax-affected; that is, they include an income tax calculation at the adjusted Test Year federal and state statutory income tax rates, expected to be in place when new retail rates go into effect. The SFR Schedule C-2 pro formas that

have a related rate base pro forma also include a calculation for synchronization of interest expense, which in turn is used in determining overall jurisdictional federal and state income tax expense.

I will discuss and explain the "Gross Revenue Conversion Factor" that is used to gross-up operating income to account for income taxes as well as an estimate of uncollectible revenue, as presented on SFR Schedule C-3, consistent with the Commission Utilities Division Staff's (Staff) recommendations in prior rate cases. In addition, I will present testimony concerning the capital structure of the Company and provide APS's actual overall cost of capital, as presented on SFR Schedules D-1 through D-4. This discussion will include information on the cost of equity provided by APS witness Dr. Roger Morin, APS's return on equity (ROE) witness, as well as the Company's embedded cost of debt. In addition, I will sponsor the various schedules relating to the Company's financial statements on SFR Schedules E-1 through E-9. SFR Schedule E-6 refers only to "combination" utilities (*e.g.*, electric and gas) and thus is not applicable to APS. Finally, I will sponsor the data on SFR Schedules F-1 through F-4. These schedules also include projected income statements and projected changes in financial position.

III. HISTORICAL AND TEST YEAR ACCOUNTING DATA

Q. PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING.

A. My testimony covers historical accounting data, including the actual data for the Test Year. The majority of this information is disclosed directly or indirectly in both the unconsolidated APS audited financial statements, which are included in filings made with the Federal Energy Regulatory Commission (FERC), and the consolidated APS and consolidated Pinnacle West audited financial statements filed with the Securities and Exchange Commission (SEC) for the relevant periods.

Additionally, all of the accounting information provided in my testimony complies with Generally Accepted Accounting Principles (GAAP), which are required by the SEC for publicly traded companies. These are the principles that accounting professionals use to prepare public financial statements. One major goal of GAAP is to make financial statements comparable from period to period, from firm to firm, and from industry to industry. It also provides consistency from jurisdiction to jurisdiction. In addition to GAAP, APS's accounting practices comply with other applicable utility accounting standards, such as the FERC Uniform System of Accounts, which this Commission has adopted for electric and gas utilities.[1] My testimony also covers the forecasted accounting statements and financial results, which are periodically supplied to investors and filed with the SEC. All of the accounting projections provided in my testimony follow GAAP and comply with other applicable utility accounting standards as mentioned above. As part of rebuttal testimony, where appropriate, APS will update forecasted and other necessary financial information to reflect the more current cost estimates.

In large part, my testimony supports the direct testimony of other APS witnesses. The testimony of Mr. Moe focuses on the jurisdictional allocation of APS revenues, costs, and rate base items for the actual Test Year and all pro forma adjustments. APS witness Jessica Hobbick's testimony addresses adjustor mechanisms, proposed changes, and related financial impacts. Dr. Morin's testimony addresses the Company's ROE.

[1] *See* A.A.C. R14-2-212(G)(2).

A. *Summary Schedules*

Q. PLEASE DESCRIBE THE HISTORICAL AND FORECASTED INFORMATION ON SFR SCHEDULES A-2 THROUGH A-5.

A. These summary schedules provide the "Summary Results of Operations," the "Summary of Capital Structure," the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service," and "Summary Changes in Financial Position" for the Test Year, the prior two calendar years and the next three calendar years. These schedules include historical and projected information. While the schedules have been prepared assuming a rate effective date of December 1, 2023, any difference in timing will be addressed in the Company's subsequent rate filing, as is typical in a rate case proceeding.

B. *Rate Base Schedules*

Q. PLEASE DESCRIBE THE INFORMATION ON SFR SCHEDULES B-1 THROUGH B-5.

A. These schedules provide summary and detailed information of APS's Original Cost Rate Base (OCRB) and Reconstructed Cost New less Depreciation (RCND) Rate Base, including the related pro forma adjustments needed to present an adjusted rate base as of the end of the Test Year. I am sponsoring the "Total Company" portion of these schedules and certain pro forma adjustments. Mr. Moe is sponsoring the ACC portion, and his testimony will present the allocation of "Total Company" figures to the ACC jurisdiction.

Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR OCRB PROPOSED BY APS.

A. As of June 30, 2022, APS is proposing a Total Company Adjusted OCRB of $13.1 billion. This represents an increase of $578.2 million over the unadjusted amount. The amount of the adjusted OCRB allocated to the ACC jurisdiction is

$10.5 billion. The requested adjustments to the Test Year amounts are summarized in SFR Schedule B-2, page 5.

Q. HAS THE COMPANY INCLUDED PENSION AND OTHER POST-EMPLOYMENT BENEFITS (OPEB) IN RATE BASE?

A. Yes, the Company has included pension and OPEB assets and liabilities in rate base. As stated in Decision No. 78317 (November 9, 2021), "Pension expense must be recognized as accounted for under GAAP as an operating expense, and plan assets, pension benefit obligations ("PBO"), and the pension components of [Other Comprehensive Income] OCI must be included in rate base to recognize the time value of money invested in pension plans." It was determined through this order that inclusion of pension and OPEB assets and liabilities in rate base is appropriate. It was further determined that the return allowed on these assets and liabilities in rate base should be at the Company's weighted average cost of capital (WACC). As such, the Company has included the total pension asset, the net OPEB liability and the net SERP liability in rate base, along with the offsetting associated ADIT within SFR Schedule B-1.

Q. WHAT IS MEANT BY THE TERMS "RCND" AND "RCN" AS USED IN YOUR TESTIMONY?

A. The Commission regulations define Reconstructed Cost New Depreciation (RCND) and Amortization as:

> An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis. (A.A.C. R14-2-103(A)(3)(n))

Thus, Reconstructed Cost New (RCN) refers to the estimated cost of utility property that would be incurred if APS were to reproduce or reconstruct the property as new, using current cost levels. RCND is the net amount that results after deducting accumulated depreciation and amortization (both of which are also restated in current dollars) from the RCN amount.

Q. WHAT DOES SFR SCHEDULE B-4 PRESENT?

A. SFR Schedule B-4 presents the RCN and RCND amounts of APS's utility properties. These amounts were determined by performing an RCN study using Handy-Whitman indices (or CPI indices for transportation equipment and general plant not covered by Handy-Whitman). Using these indices has been a long-standing practice by all major utilities in Arizona and accepted by the Commission and the industry in general for determining the RCN amount.

Q. BASED ON YOUR STUDY, WHAT IS THE RCN OF APS'S UTILITY PROPERTY DEVOTED TO SERVICE TO THE PUBLIC AS OF THE END OF THE TEST YEAR?

A. Total RCN for APS's utility property is $46.2 billion. This total amount is shown in column (A) of SFR Schedule B-4, page 2 of 2.

Q. WOULD YOU PLEASE EXPLAIN HOW RCND WAS CALCULATED AS SHOWN ON SFR SCHEDULE B-4?

A. To arrive at RCND, the RCN column (A) is multiplied by a "condition percent," also known as a net book value percent, which is shown in column (B). The RCND is shown in column (C). The condition percent used to convert RCN to RCND is calculated by first determining the net book value (original cost less accumulated depreciation and removal costs) for all depreciable plant by each FERC plant account. This amount is then divided by the original cost for each FERC account to arrive at the condition percent. In other words, the condition percent is the

percentage that results when comparing net book value to the original cost of plant in service.

For example, assume that distribution lines have an original cost of $400,000, and accumulated depreciation and removal costs of $250,000. The net book value would be $150,000 ($400,000 less $250,000). Also, assume the distribution lines were purchased in 1985 and have an RCN value of $632,000. Using these assumptions, the condition percent is calculated by dividing original cost less accumulated depreciation and removal costs by original cost, or $150,000/$400,000, resulting in a condition percent of 37.5%. Multiplying the RCN of $632,000 by the condition percent of 37.5% yields $237,000 of RCND.

Q. ARE THERE ANY OTHER RELATED ADJUSTMENTS NECESSARY TO DETERMINE FAIR VALUE RATE BASE?

A. Yes. Plant-related ADIT were also adjusted. Plant-related ADIT arises primarily as a result of differences between book depreciation recorded for GAAP purposes and tax depreciation used for income tax purposes. Since RCND trending results in a change in accumulated book depreciation, a corresponding change was made to original cost ADIT. To make this adjustment, the Company trended plant-related ADIT using the relationship between the OCRB less depreciation and RCND.

Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE B-4A?

A. SFR Schedule B-4a shows the computation of adjusted jurisdictional RCND Rate Base as of June 30, 2022. Column (A) presents data for Total RCND Rate Base. Mr. Moe provided the jurisdictional allocations of the RCND Rate Base split between "ACC" and "Other," which is presented in columns (B) and (C), respectively.

Q. HOW DID YOU ARRIVE AT THE AMOUNTS SHOWN ON LINES 9 THROUGH 31 OF SFR SCHEDULE B-4A?

A. The amounts shown on lines 9 through 31 of SFR Schedule B-4a for other rate base elements were obtained from SFR Schedule B-1, page 2 of 2, column (A). Consistent with past Commission practice, the RCND of these specific rate base elements are stated at their original cost levels, as these elements are assumed not to change in value with the passage of time, with the exception of deferred income taxes and regulatory liabilities as a result of excess deferred tax amortization.

Q. WOULD YOU PLEASE EXPLAIN LINES 32 AND 33 OF SFR SCHEDULE B-4A?

A. The amounts shown on line 32 represent the RCND rate base as of June 30, 2022. However, the end of Test Year data needs to be adjusted to more closely reflect the value of certain items of property when the proposed rates become effective. Therefore, it is necessary to also reflect the pro forma rate base adjustments in the RCND rate base. The RCND pro forma adjustments are shown in detail in SFR Schedule B-3. The total pro formas are shown on line 33 of SFR Schedule B-4a.

Q. WHAT IS THE TOTAL ADJUSTED RCND RATE BASE?

A. The Total Company RCND rate base, as adjusted, is $27.8 billion. This is shown in SFR Schedule B-4a, column (A), line 34.

Q. PLEASE EXPLAIN THE COMPUTATION OF WORKING CAPITAL ON SFR SCHEDULE B-5.

A. SFR Schedule B-5 outlines the computation of the allowance for working capital of $506.5 million included in the Company's rate base. Working capital is a measure of investor funding of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations. Working capital includes materials and supplies, fuel inventories, prepayments, and cash working capital. Working capital is an investment just like other capital requirements, such

as power plants and transmission and distribution infrastructure; thus, it is part of APS's rate base. My testimony presents the calculation of the allowance for working capital, which includes a cash working capital component that is determined using a lead/lag study. The lead/lag study is required by Decision No. 55931 (April 1, 1988).

Q. HOW WAS THE CASH WORKING CAPITAL CALCULATED?

A. APS calculated the cash working capital by performing a lead/lag study. A lead/lag study establishes the amount of investor funds used to maintain utility operations from the time expenditures are made to the time revenues are collected as a reimbursement for that utility service. The Company used the number of lead/lag study days derived from a 12-month period ending June 30, 2022 and applied this information to the Test Year income statement expenses.

In addition, the Company considered the pro forma adjustments to the Test Year income statement expenses and computed a rate base pro forma to reflect the related change in cash working capital (*see* Section IV, Pro Forma Adjustments to Test Year).

C. *Test Year Income Statements*

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULE C-1.

A. SFR Schedule C-1 is a summary of the Company's adjusted Test Year income statement. I am sponsoring the actual Test Year data in the first column of SFR Schedule C-1, page 1. Mr. Moe sponsors the ACC jurisdictional data in the first column on page 2. This information provides the baseline from which pro forma adjustments are made and shows operating income and net income for the Test Year.

Q. ARE YOU SPONSORING ANY OTHER RELATED SFR SCHEDULES?

A. Yes. I am sponsoring the Total Company amounts for certain pro forma adjustments on SFR Schedule C-2, which presents pro forma adjustments to the Company's Test Year operating income. Mr. Moe sponsors the ACC jurisdictional amounts on this schedule. I will discuss these adjustments in detail later in my testimony (*see* Section IV, Pro Forma Adjustments to Test Year). I am also sponsoring SFR Schedule C-3, which provides the "Computation of Gross Revenue Conversion Factor."

Q. PLEASE DESCRIBE SFR SCHEDULE C-3.

A. SFR Schedule C-3 calculates the factor applied to "gross-up" income to account for income taxes as well as an estimated percentage of uncollectible revenue. The Company applies this factor to operating income to ensure income tax expense is reflected in the requested revenue requirement. The Gross Revenue Conversion Factor of 1.3359 (line 8) is an algebraic transformation of gross revenue adjusted for uncollectable revenue and the Test Year Composite Tax rate of 24.61% (line 6). This factor is used on SFR Schedule A-1 (line 7) to arrive at the increase or decrease in Revenue Requirements necessary to account for income taxes.

D. *Cost of Capital*

Q. PLEASE DISCUSS THE COST OF CAPITAL INFORMATION THAT YOU ARE SPONSORING.

A. SFR Schedule D-1 is a summary of the Company's historical and projected cost of capital. SFR Schedule D-2 presents supporting detail for the long-term debt summarized on SFR Schedule D-1. SFR Schedule D-3 addresses preferred stock and is included in the Company's schedules for the sake of completeness. SFR Schedule D-3 is not applicable because APS did not have any outstanding preferred stock as of June 30, 2022. SFR Schedule D-4 addresses the Company's cost of common equity.

Q. WHAT IS THE COST OF CAPITAL THE COMPANY IS REQUESTING?

A. The Company is requesting an adjusted weighted average cost of capital (WACC) of 7.17% as set forth on SFR Schedule D-1 (line 5, column D), page 1 of 2.

Q. PLEASE DISCUSS IN MORE DETAIL THE COMPANY'S OUTSTANDING LONG-TERM DEBT AS OF THE END OF THE TEST YEAR.

A. At the end of the Test Year, approximately 99% of APS's outstanding long-term debt consisted of unsecured debt with a weighted average interest rate of 3.84%. The remaining long-term debt consisted of tax-advantaged pollution control bonds, which had a weighted average interest rate of 1.39%.

Q. WHAT WAS APS'S CAPITAL STRUCTURE AT THE END OF THE TEST YEAR?

A. APS's total long-term debt and common equity was $13.1 billion. This amount includes $6.3 billion in long-term debt and $6.8 billion in common equity. APS's adjusted capital structure at the end of the Test Year was 48.07% debt and 51.93% equity.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE CAPITAL STRUCTURE AND COST OF CAPITAL?

A. I have applied two pro forma adjustments to the June 30, 2022 actual capital structure. The first adjustment to the capital structure removes short-term debt, as it is recoverable through the Allowance for Funds Used During Construction (AFUDC) provisions. The second adjustment removes the impacts to equity of non-cash accounting adjustments for SERP.

Q. WHAT RETURN ON EQUITY IS THE COMPANY REQUESTING?

A. Dr. Morin concludes in his testimony that the fair rate of return on equity for APS is 10.25%. The Company is adopting Dr. Morin's recommendation for purposes of this filing.

E. *Financial Statements and Statistical Schedules*

Q. PLEASE SUMMARIZE THE INFORMATION PRESENTED ON SFR SCHEDULES E-1 THROUGH E-9.

A. These schedules relate to historical financial and accounting information as well as the notes to the financial statements. As noted earlier in my testimony, SFR Schedule E-6 is only required for combined electric and gas utilities and, therefore, does not apply to APS.

Q. PLEASE DISCUSS SFR SCHEDULES E-1 THROUGH E-4.

A. These schedules present APS's balance sheets, income statements, statements of changes in financial position, and changes in stockholders' equity for the Test Year and the two prior calendar years. As discussed earlier, these financial statements continue to reflect APS's unconsolidated results, consistent with previous rate filings. The APS FERC Form 1 and Form 3Q filings that support these schedules and are provided in SFR E-9, reflect APS's unconsolidated regulated financial statements.

Q. PLEASE DISCUSS SFR SCHEDULE E-5.

A. SFR Schedule E-5 is a detailed statement of utility plant included in the Company's rate base, broken down by FERC account under the Uniform System of Accounts. The first page of SFR Schedule E-5 is a summary of gross plant in service, accumulated depreciation and amortization, nuclear fuel, construction work in progress (CWIP), plant held for future use, and plant acquisition adjustment. The remainder of the schedule presents supporting detail for each FERC plant account.

Q. WHAT INFORMATION IS PROVIDED ON SFR SCHEDULE E-7?

A. SFR Schedule E-7 provides detailed information concerning APS's sales (in kWh), average number of customers, average kWh usage per customer, and average annual revenue per residential customer over the last three years, including the Test Year. This information is contained in or derived from APS's FERC Form 1 and

Form 3Q filings for the applicable periods. The information in SFR Schedule E-7 is separated by customer classes to show residential, commercial, industrial, irrigation, public street and highway lighting, other sales to public authorities, and sales for resale.

Q. PLEASE DISCUSS SFR SCHEDULE E-8.

A. SFR Schedule E-8 provides a breakdown of APS's tax expense incurred during the Test Year and the two prior calendar years for federal and state taxes.

Q. PLEASE DISCUSS SFR SCHEDULE E-9.

A. SFR Schedule E-9 presents the Company's unconsolidated financial statements and footnotes as filed in the Company's FERC Form 1 for 2021, Form 10-Q for the six months ended June 30, 2021 and Form 10-Q for the six months ended June 30, 2022. The footnotes include, but are not limited to, the Company's accounting policies for depreciation, allowance for funds used during construction (AFUDC) and income taxes. The footnotes also provide additional detailed information related to the income statements, the balance sheets, and statements of cash flows.

F. *Projections and Forecasts*

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULES F-1 THROUGH F-4.

A. SFR Schedule F-1 presents income statements for projected calendar years, compared with actual Test Year results, at present and proposed rates. As I have previously indicated, Schedule F-1, like Schedule A-2, shows key information relating to the Company's actual and projected ROE. As Schedule F-1 shows, under APS's present rates, the Company's ROE on end-of-year equity falls from 8.4% at the end of the Test Year to under 6% by 2024—well below any reasonable ROE found in Dr. Morin's testimony as required to maintain the financial stability of APS to support investment necessary to meet customers' needs. It is important to note that even with the Company's proposed rates, the Company's ROE in 2024

would still be below the cost of equity capital, but significantly better than the 5.7% projected under present rates. SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years compared with the Test Year, at present and proposed rates. SFR Schedule F-3 presents projected annual capital expenditure requirements, by property classification, for two and a half years subsequent to the Test Year. Finally, SFR Schedule F-4 presents the key assumptions used in developing the projections.

IV. PRO FORMA ADJUSTMENTS TO TEST YEAR

A. *Types of Pro Forma Adjustments*

Q. WHAT ARE PRO FORMA ADJUSTMENTS?

A. Pro forma adjustments are adjustments made to a historical test year to reflect conditions during the period in which rates are to be in effect. Because the Company has used a historical test year, it is necessary to adjust recorded revenues and expenses for known and measurable changes. Pro forma adjustments commonly include normalizations, annualizations and out-of-period adjustments. All of the pro forma adjustments discussed in my testimony reflect Total Company amounts prior to any jurisdictional allocation, and are reflected on either SFR Schedule B-2 or SFR Schedule C-2.

Q. WHAT ARE NORMALIZATIONS?

A. Normalization adjustments compensate or adjust for unusual levels of operations experienced during the Test Year period. These adjustments generally relate to items that are abnormal in amount or nonrecurring in nature and are made to better reflect what is believed to be an ongoing level of operations.

Q. WHAT ARE ANNUALIZATIONS?

A. Annualization adjustments recognize that some events occurring during the Test Year period are ongoing and must be adjusted to reflect their impact over an entire 12-month period. One example of an annualization is for payroll costs. Since

payroll costs can be higher or lower on an ongoing basis than what was recorded during the Test Year, an adjustment must be made to reflect the prospective level of costs.

Q. WHAT IS AN "OUT-OF-PERIOD" OR MISCELLANEOUS ADJUSTMENT?

A. Out-of-period adjustments remove expenses or revenues properly recorded during the Test Year but which are associated with operations from another year. Miscellaneous adjustments remove costs from the Test Year for items which the Company does not intend to collect from customers.

Q. ARE THERE ANY OTHER TYPES OF ADJUSTMENTS THE COMPANY MADE TO THE TEST YEAR?

A. Yes. As a result of the historical Test Year containing seven months of updated rates effective December 1, 2021, as ordered in Decision No. 78317, several pro forma adjustments were made to reflect an on-going annualized level of costs that were approved for recovery from this decision but that are not contained in the Test Year. These pro forma adjustments reflect a full 12 months or annualized amount.

B. *Pro Forma Adjustment Descriptions*

1. Adjust for Post-Test Year Plant Additions

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ACCOUNT FOR POST-TEST YEAR PLANT (PTYP) ADDITIONS?

A. APS witness Jacob Tetlow addresses the details of the Company's capital investments in his direct testimony. The Company is proposing to include plant additions that go into service after the Test Year (July 1, 2022 to June 30, 2023), but well before new base rates are expected to be in effect. My testimony covers the mechanics of the pro formas, as discussed below:

Step 1: CWIP was extracted from the general ledger as of June 30, 2022 for non-transmission plant that is expected to go into service on or before June 30, 2023;

Step 2: The forecast plant in service cost of each project that is expected to go into service on or before June 30, 2023 was compiled (projects in CWIP at June 30, 2022, and projects that began after June 30, 2022 but are expected to be completed and in service within 12 months), and all growth-related plant additions are excluded at this point;

Step 3: The plant was classified by functional area: nuclear generation, renewable generation, other generation, distribution, information technology/facilities, and customer technology innovation;

Step 4: Annual accumulated depreciation and amortization, net of accumulated deferred income taxes, and tax credits (where applicable), were offset against the PTYP additions adjustment;

Step 5: The sum of the forecast plant in service costs, less accumulated depreciation and deferred income taxes and other associated tax credits as applicable, was presented by functional unit and included in the rate base pro forma adjustments that increase rate base at June 30, 2022 by $788.8 million (*see* SFR Schedule B-2, pages 1 and 2, columns 2 through 6, line 6); and

Step 6: Property taxes and depreciation expense were calculated and reflected as a reduction to pre-tax operating income of $78.8 million (*see* SFR Schedule C-2, pages 1 and 2, columns 1 through 5).

APS will true-up this adjustment with actual plant placed in service, net of retirements, throughout the case.

Q. DID THE COMPANY INCLUDE ANY TAX CREDIT BENEFITS IT EXPECTS TO RECEIVE UNDER THE INFLATION REDUCTION ACT FOR ITS POST-TEST YEAR CLEAN ENERGY AND ENERGY STORAGE ADDITIONS?

A. Yes. As addressed in APS witness Andrew Cooper's Direct Testimony, the Inflation Reduction Act of 2022 (IRA) extended and expanded the federal tax credits available for clean energy and energy storage investments. The Company's PTYP pro forma includes an offset for Investment Tax Credits (ITC) of $77.3 million related to energy storage investments of which the Company is seeking recovery. With regard to its post-Test Year solar investments, the Company intends to claim the Production Tax Credit (PTC) which was enacted under the IRA. When the PTC is earned (i.e., when energy is produced by PTYP solar facilities that qualify for the tax credit), the Company is proposing to include any such PTC related to its solar post-Test Year investments as a part of the expanded Renewable Energy Adjustment Charge, keeping costs affordable for customers for these post-Test Year investments by passing savings from any PTCs to customers in a timely manner.

2. Remove, Transfer, and Annualize Test Year Surcharge Revenue and Expenses

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE, TRANSFER, AND ANNUALIZE TEST YEAR SURCHARGE REVENUES AND EXPENSES.

A. This pro forma captures several types of adjustments made to revenue and expense to account for the amounts collected or refunded during the Test Year under adjustor mechanisms, including regulatory assessments. Adjustor mechanisms and regulatory assessments are not collected or refunded as part of base rates, so they must first be excluded from Test Year revenue to calculate new base rates, with the exception of those adjustor revenues and expenses that are either in total or in part proposed to be transferred into base rates. Ms. Hobbick, in her testimony, supports the Company's adjustor mechanisms and any proposed changes requested to those in this case. Her testimony also supports the proposed treatment of the Test Year adjustor mechanisms revenue and expense in deriving base rates. This results in a reduction to pre-tax operating income of $36.6 million. (*See* SFR Schedule C-2, page 4 through 6, columns 11 through 18.)

3. Include West Phoenix Unit 4 Regulatory Disallowance

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE.

A. This disallowance was recorded for regulatory purposes as ordered by Decision Nos. 67744 (April 7, 2005) and 69663 (June 28, 2007) but did not qualify as a disallowance for GAAP purposes. Consequently, a pro forma adjustment is needed to reduce rate base by the disallowed amount. Accordingly, the rate base reduction for the West Phoenix Unit 4 regulatory disallowance at June 30, 2022 is $4.8 million. (S*ee* SFR Schedule B-2, page 3, column 7.)

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE DEPRECIATION EXPENSE RELATED TO THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE?

A. Yes. The operating income pro forma reflects an annual reduction in depreciation expense. This results in an increase to pre-tax operating income of $329,000. (S*ee* SFR Schedule C-2, page 7, column 20.)

4. Include Interest Expense on Customer Deposits

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR INTEREST EXPENSE ON CUSTOMER DEPOSITS.

A. This pro forma adjustment reflects the annualized interest cost associated with customer deposits as an operating expense. This treatment conforms to the approach used by the Commission in the Company's previous rate cases. This adjustment was calculated by applying the 0.40% annual 2022 interest rate to the June 30, 2022 outstanding deposit balance. The annual interest rate is the rate required by APS Schedule 1 for customer deposits—the established one-year Treasury Constant Maturities rate, effective on the first business day of each year (in this instance, January 1, 2022), as published on the Federal Reserve website. The result of this pro forma is a reduction to pre-tax operating income of $160,000. (*See* SFR Schedule C-2, page 7, column 21.)

5. Include E-3/E-4 Customer Bill Payment Fees Deferral

Q. PLEASE DESCRIBE THE ADJUSTMENT TO INCLUDE E-3/E-4 CUSTOMER BILL PAYMENT FEES DEFERRAL.

A. The Company was authorized in Decision No. 78317 to track and defer for future recovery the amounts paid on behalf of customers under certain limited-income discount programs, Rate Riders E-3 and E-4, including the credit card processing fee. This rate base pro forma annualizes the amounts deferred in the Test Year to include the estimated E-3/E-4 customer bill payment fees deferral amount from

July 1, 2022 to December 1, 2023 (estimated rate effective date). Accordingly, the rate base increase for the E-3/E-4 Customer Bill Payment Fees Deferral is $574,000. (S*ee* SFR Schedule B-2, page 4, column 12.)

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE AMORTIZATION RELATED TO E-3/E-4 CUSTOMER BILL PAYMENT FEES DEFERRALS?

A. Yes, the Company is requesting to amortize the deferral over a three-year period. This pro forma adjustment results in a reduction to pre-tax operating income of $270,000. (S*ee* SFR Schedule C-2, page 9, column 25.)

6. Annualize Depreciation Expense – 2019 Approved Depreciation Rates

Q. WHAT ADJUSTMENTS HAVE THE COMPANY MADE TO DEPRECIATION AND AMORTIZATION EXPENSE?

A. For this filing, APS utilized the 2019 Depreciation Rates contained in the 2019 Depreciation Rate Study performed by Dr. Ronald E. White and approved and authorized in Decision No. 78317. This pro forma adjustment increases depreciation expense and thus results in a reduction to pre-tax operating income of $44.7 million. (*See* SFR Schedule C-2, page 9, column 26 and Attachment EAB-01DR.)

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?

A. No, APS is not requesting any change to the amortization rates authorized in Decision No. 78317.

Q. IS THE COMPANY PROPOSING TO ACCELERATE THE DEPRECIATION OF FOUR CORNERS?

A. No, APS proposes to continue depreciation of the Four Corners Power Plant (Four Corners) until 2038 as previously communicated to the Commission and in agreement with the most recent Commission authorized depreciation study.

7. Annualize Payroll Expense

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ANNUALIZE PAYROLL EXPENSE.

A. This pro forma adjustment decreases Test Year expense mainly as a result of a decrease in average wage levels and fewer employees. This pro forma adjustment annualizes the Test Year payroll and payroll tax expense to June 2022 employee and wage levels for non-union and union employees (per the current union contract finalized in 2020 and in effect until 2023). Any subsequent changes in union payroll as a result of a renegotiated contract will be reflected in rebuttal testimony. This results in an increase to pre-tax operating income of $2.1 million (*see* SFR Schedule C-2, page 9, column 27).

Q. DOES THIS TOTAL PAYROLL ADJUSTMENT ONLY AFFECT OPERATIONS AND MAINTENANCE?

A. Yes. This adjustment excludes capitalized payroll costs. This Operations and Maintenance (O&M) adjustment was estimated by calculating the percentage of APS's O&M payroll to total payroll during the Test Year. The total payroll and payroll taxes were allocated to O&M based on the same Test Year O&M percentage payroll amounts.

8. Normalize Employee Benefits

Q. PLEASE EXPLAIN THE NEED FOR THE EMPLOYEE BENEFIT PRO FORMA ADJUSTMENT.

A. This adjustment is necessary to appropriately recognize the costs associated with pension and other OPEB plans, which are primarily medical benefits for eligible retirees. This adjustment is consistent with the adjustment recommended by Staff in Decision No. 69663 and used by the Company in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), 76295 (August 18, 2017), and 78317.

Q. HOW WAS THE EMPLOYEE BENEFITS PRO FORMA ADJUSTMENT DETERMINED?

A. The total change in pension and OPEB expense is the difference between the Test Year expense and the 2022 level of that expense, as determined by APS's actuaries, Willis Towers Watson. As noted below, this calculation resulted in an increase to employee benefits expense.

Q. HOW DID YOU DETERMINE THE AMOUNT OF INCREASED BENEFITS COSTS PROPERLY ALLOCABLE TO APS'S O&M?

A. An APS allocation factor was calculated and applied to the total Pinnacle West change in benefit expenses. This allocation factor was determined by dividing APS's 12 months ended June 30, 2022 actual O&M employee benefits by the total actual employee benefits costs for Pinnacle West for the same 12-month period. This results in a reduction to pre-tax operating income of $5.2 million (*see* SFR Schedule C-2, page 10, column 28).

9. Remove Supplemental Excess Benefit Retirement Plan Expense

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO REMOVE SERP.

A. This pro forma removes from expense the associated costs of Test Year operations SERP. This results in an increase to pre-tax operating income of $7.6 million (*see* SFR Schedule C-2, page 10, column 29).

10. Remove Stock Compensation

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO REMOVE STOCK COMPENSATION.

A. This pro forma removes the Test Year level of expense associated with stock compensation. This results in an increase to pre-tax operating income of $11.3 million (*see* SFR Schedule C-2, page 10, column 30).

11. Include Active Union Medical Trust Interest Income and Realized Gains

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO INCLUDE THE ACTIVE UNION MEDICAL TRUST INTEREST INCOME AND REALIZED GAINS.

A. This pro forma adjustment reflects the Test Year level of interest income and realized gain on investments in the Active Union Medical Account. This results in an increase to pre-tax operating income of $3.5 million (*see* SFR Schedule C-2, page 11, column 31).

12. Normalize Cash Incentive Expense

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO NORMALIZE CASH INCENTIVE.

A. This pro forma normalizes the associated costs of Test Year operations for the cash incentive program over a three-year period. The use of this three-year normalization of cash incentive expense was first proposed by Staff and adopted

by the Commission in Decision No. 71448. This results in a reduction to pre-tax operating income of $8.2 million (*see* SFR Schedule C-2, page 11, column 32).

13. Normalize Income Tax Expense/Interest Synchronization

Q. WHAT METHODOLOGY DID YOU USE TO DETERMINE THE FEDERAL AND STATE INCOME TAX PRO FORMA ADJUSTMENT?

A. The Company used a "top down" approach in computing cost-of-service income tax expense. This calculation, which was also adopted in Decision No. 69663 and consistently used thereafter, uses the statutory rate and estimated Test Year levels of various tax credits and other permanent tax items, adjusted for known changes (*e.g.*, amortization of excess deferred taxes resulting from the Tax Cuts and Jobs Act), reflecting the Company's best estimate of on-going income tax expense. It also considers the deduction of interest expense synchronized to the end of the Test Year's rate base. The total federal and state income tax pro forma increases income tax expense by $3.0 million (*see* SFR Schedule C-2, page 11, column 33).

14. Annualize Property Tax Expense

Q. HAS APS PROPOSED AN ADJUSTMENT TO THE TEST YEAR AD VALOREM (PROPERTY) TAX?

A. Yes. An adjustment is appropriate to reflect June 30, 2022 plant values, the current state assessment ratios, and the most current estimated composite tax rate.

Q. HOW WERE PROPERTY TAXES CALCULATED?

A. Property taxes were calculated using June 30, 2022 property values as filed with the Arizona Department of Revenue in April 2022. These property values were then multiplied by the most current approved assessment ratios. Finally, that assessed value is multiplied by the actual current estimated composite tax rate. APS will update the expected composite tax rate with the actual rate when it becomes available near the end of the fourth quarter of 2022. This adjustment results in a

reduction to pre-tax operating income of $9.5 million (*see* SFR Schedule C-2, page 12, column 34).

15. Include and Annualize Property Tax Deferral Amortization

Q. IS THE COMPANY REQUESTING A PROPERTY TAX DEFERRAL MECHANISM?

A. The Company is not requesting a rate base pro forma adjustment or on-going property tax deferral approval. However, as discussed below, there are pro forma adjustments needed to reflect prior Commission decisions.

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENTS TO OPERATING INCOME FOR THE PROPERTY TAX DEFERRAL.

A. There are two operating income adjustments related to the property tax deferral that was authorized in Decision No. 78317. The first pro forma adjustment reflects the annual level of amortization to be refunded to customers that was authorized in Decision No. 78317, since the Test Year in this case only includes seven months of that allowed amortization. The second pro forma adjustment reflects the additional annual level of amortization to be refunded to customers that the Company is requesting in this case, which is related to the residual amount of property tax expense that the Company continued deferring under prior Commission order up until the December 1, 2021 rate effective date of Decision No. 78317 (amounts deferred from December 31, 2020 through December 1, 2021). Both pro formas reflect an annual refund, or benefit, to customers. APS requests to amortize this refund over a three-year period consistent with the related deferral amortization authorized in Decision No. 78317 for this matter. These pro forma adjustments result in an increase to pre-tax operating income of $1.9 million and $2.2 million, respectively (*see* SFR Schedule C-2, page 12, columns 35 and 36, respectively).

16. Annualize Four Corners Coal Reclamation Costs

Q. PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE FOUR CORNERS COAL RECLAMATION COSTS.

A. This pro forma adjustment for Four Corners coal reclamation annualizes the estimate for final reclamation costs, the costs to account for inflation, and the amortization period for Four Corners. The estimate for final reclamation costs is based on a study performed by Golder Associates as of September 2019. The costs within the Golder Associates study were presented on a December 2019 dollar basis. Due to the long-term nature of these costs, APS escalated the cost estimates for Four Corners through June 2031, which is aligned with the terms of the coal supply agreement. The Company is using an amortization period to June 2038. The result is an increase to pre-tax operating income of $1.5 million (*see* SFR Schedule C-2, page 13, column 37).

Q. HOW WAS THE ESCALATION CALCULATED?

A. Total estimated costs from the Golder Associates study were used to derive APS's share of Four Corners coal reclamation (in 2019 dollars). The reclamation costs for Four Corners are inflated using an annual rate of 4% over 12.5 years to adjust the 2019 dollar basis to second quarter 2031, which is the end of the coal contract. Per the current coal supply agreement, APS shall fund Final Reclamation in 13 equal annual installments, on August 1 of each Contract Year (beginning August 2018) into an irrevocable escrow account, solely dedicated to the Final Reclamation Costs of the Navajo Mine (the Escrow Account). The funding will be based on the initial final reclamation estimates with true-ups for updates of estimates made periodically. The Company is using an amortization period to June 2038.

17. Annualize Navajo Coal Reclamation Costs

Q. PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE NAVAJO COAL RECLAMATION COSTS.

A. This pro forma adjustment for Navajo coal reclamation annualizes the final reclamation costs over the original plant life of June 2026. APS finalized the settlement of the Navajo final coal reclamation obligation with Peabody based on a study prepared by Golder Associates. This results in a reduction to pre-tax operating income of $2.1 million (*see* SFR Schedule C-2, page 13, column 38).

18. Adjust Cash Working Capital for Cost of Service

Q. PLEASE DESCRIBE THE PRO FORMA TO ADJUST CASH WORKING CAPITAL FOR COST OF SERVICE PRO FORMAS.

A. This is a rate base pro forma to adjust cash working capital to include the effects of the cost-of-service pro formas. As discussed earlier in my testimony, the cash working capital on SFR Schedule B-5 includes a cash working capital component determined using a lead/lag study. The expense levels in that study reflect the actual expense in the Test Year. This pro forma adjusts the study to take into consideration the cost-of-service pro formas which adjust actual Test Year levels of expense. This pro forma reduces rate base at June 30, 2022 by $15.2 million (*see* SFR Schedule B-2, page 3, column 8).

Q. ARE THERE ANY ADDITIONAL IMPACTS OF THIS RATE BASE PRO FORMA?

A. Yes. Since the rate base pro forma affects total rate base, there is a corresponding operating income pro forma necessary to reflect the income tax impacts of interest. This pro forma was calculated using the rate base adjustment above and the weighted cost of debt. This adjustment increases income tax expense by $69,000 (*see* SFR Schedule C-2, page 13, column 39).

19. Normalize Nuclear and Fossil Maintenance Expenses

Q. PLEASE DESCRIBE THE PRO FORMAS TO NORMALIZE NUCLEAR AND FOSSIL MAINTENANCE.

A. These pro formas adjust for both planned maintenance time and unplanned outage time so that the level of maintenance expense included in the Test Year is consistent with an average year. These adjustments are necessary because outage time at each of the power plants in the Test Year for planned routine maintenance and unplanned forced outages is not indicative of the normal levels of availability. APS adjusted Test Year O&M expenses to normalize maintenance levels for the Company's production plant in service at June 30, 2022. This was done separately for the Company's nuclear facilities and its fossil facilities.

The nuclear generation maintenance adjustment increases pre-tax operating income by $431,000 and the fossil generation maintenance adjustment reduces pre-tax operating income by $28.0 million. The O&M expense adjustments include the impacts of the outage time normalization for all of the units. (*See* SFR Schedule C-2, page 14, columns 40 and 41.)

Q. HOW DID YOU ADJUST THE OUTAGE TIME TO NORMALIZE THE TEST YEAR RESULTS?

A. Planned maintenance time for each non-nuclear generating plant is an average over the routine overhaul cycle for the plant type. For example, the Company's fossil plants are on a six-year overhaul cycle, which means that each of the fossil units should experience a major overhaul once in every six-year period. The specific six-year period applicable to the normalization includes the historical years of 2017 through the 12 months ended June 30, 2022.

Normalized Palo Verde Generating Station (PV) outage time is calculated in a similar manner, using a three-year period spanning 2020 through the 12 months ended June 30, 2022, but the rationale is slightly different than the one applicable to the fossil outage time normalization. The nuclear units are each on an 18-month refueling cycle, so a three-year period ensures that each unit's maintenance time is reflected in equal proportion in the normalization period. Any single year, such as the Test Year, does not represent the average maintenance time and associated expense levels that can reasonably be expected when rates established in this case will be in effect.

Q. HOW DID YOU ADJUST THE MAINTENANCE EXPENSES TO NORMALIZE THE TEST YEAR RESULTS?

A. The maintenance expenses were normalized in a similar fashion to the outage time. For fossil generating units, normal maintenance levels are determined by averaging the historical maintenance expense at each power plant using the six-year average maintenance cycle. Normal PV expenses are based on historical expenses for a three-year period.

Labor costs, including overtime costs, have been adjusted to reflect historical labor cost increases. Non-labor maintenance costs were adjusted to current cost levels using the relevant Handy-Whitman cost indices.

20. Annualize Sundance Maintenance Expense Accrual

Q. PLEASE DESCRIBE THE PRO FORMA TO ADJUST THE SUNDANCE MAINTENANCE EXPENSE ACCRUAL.

A. This pro forma annualizes the accrual of the overhaul maintenance costs associated with the Sundance Units as authorized in Decision Nos. 69663 and 78317. This adjustment results in a reduction to pre-tax operating income of $2.0 million (*see* SFR Schedule C-2, page 14, column 42).

21. Remove Navajo Power Plant Costs

Q. PLEASE DESCRIBE THE PRO FORMA TO REMOVE NAVAJO POWER PLANT COSTS.

A. This pro forma removes the Test Year O&M expense as well as administrative and general expenses as a result of the closure of the Navajo Generating Station (Navajo) in December 2019. This adjustment results in an increase to pre-tax operating income of $56,000 (*see* SFR Schedule C-2, page 15, column 43).

22. Include Navajo Regulatory Asset Amortization Disallowance

Q. PLEASE DESCRIBE THE PRO FORMA TO INCLUDE THE NAVAJO REGULATORY ASSET AMORTIZATION DISALLOWANCE.

A. This pro forma reflects the 15% regulatory disallowance of the Navajo regulatory asset amortization that was ordered in Decision No. 78317. As this does not qualify as a disallowance for GAAP purposes, a pro forma adjustment is needed to the Test Year to reflect the reduction in depreciation expense. This results in an increase to pre-tax operating income of $1.4 million (*see* SFR Schedule C-2, page 15, column 44).

Q. IS THERE A CORRESPONDING RATE BASE PRO FORMA ADJUSTMENT RELATED TO THE NAVAJO REGULATORY ASSET AMORTIZATION DISALLOWANCE?

A. Yes. As a result of the 15% regulatory disallowance of the Navajo regulatory asset amortization that was ordered in Decision No. 78317, there must also be a corresponding rate base pro forma adjustment to ADIT to avoid an IRS normalization rule violation, which was also approved in Decision No. 78317. This results in a rate base increase of $2.1 million (*see* SFR Schedule B-2, page 4, column 10).

23. Include and Annualize Ocotillo Modernization Project Deferral Amortization and Include Equity Return Disallowance

Q. PLEASE EXPLAIN THE OPERATING INCOME PRO FORMA ADJUSTMENTS FOR THE OCOTILLO MODERNIZATION PROJECT DEFERRAL.

A. In Decision No. 76295, APS was allowed to defer for later recovery all non-fuel costs of owning, operating and maintaining the Ocotillo Modernization Project (OMP) and retiring the existing steam generation at Ocotillo and to accrue interest at the cost of debt approved in the 2016 Rate Case (*see* Decision No. 76295, Exhibit A, Section 10). In the Company's last rate case, APS requested recovery of the OMP deferral in rate base with a corresponding increase to operating expenses to reflect an annual level of amortization over ten years. Decision No. 78317 authorized the requested rate base inclusion and corresponding operating income increase, however with a return set at the 4.10% embedded cost of debt in that case.

There are three operating income adjustments related to the OMP deferral that were authorized in Decision No. 78317. The first pro forma adjustment reflects the annual level of amortization that was authorized in Decision No. 78317, since the Test Year in this case only includes seven months of that allowed amortization. The second pro forma adjustment reflects the additional annual level of amortization that the Company is requesting in this case, which is related to the residual amount of OMP deferred costs that the Company continued deferring under prior Commission order up until the December 1, 2021 rate effective date of Decision No. 78317 (amounts deferred from December 31, 2020 through December 1, 2021). APS requests to amortize this residual deferral amount over a ten-year period consistent with the related deferral amortization authorized in Decision No. 78317 for the same matter. The third pro forma adjustment reflects

the equity return disallowance on the deferral as authorized in Decision No. 78317. These pro forma adjustments result in a reduction to pre-tax operating income of $4.0 million and $5.3 million, respectively, related to the OMP deferral amortization and an increase to pre-tax operating income of $4.4 million related to the equity return disallowance (*see* SFR Schedule C-2, page 15, column 45, and page 16, columns 46 and 47).

24. Include Four Corners Selective Catalytic Reduction (SCR) Regulatory Disallowance and Adjust Depreciation Expense

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR THE FOUR CORNERS SELECTIVE CATALYTIC REDUCTION (SCR) DISALLOWANCE.

A. Decision No. 78317 authorized APS to include a portion of the SCRs investments in rate base, with the exception of $215.5 million. This disallowance was reflected for regulatory purposes but does not qualify as a disallowance for GAAP purposes; thus, a pro forma adjustment is necessary to reduce rate base by the disallowed amount. Accordingly, the rate base reduction is $215.5 million (*see* SFR Schedule B-2, page 4, column 11).

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE DEPRECIATION EXPENSE RELATED TO THE FOUR CORNERS SCR DISALLOWANCE?

A. Yes. There is a corresponding operating income pro forma adjustment related to the Four Corners SCR disallowance that reflects the annual reduction in depreciation expense related to the $215.5 million SCR rate base disallowance discussed above and the additional direction ordered in Decision No. 78317 to accelerate the depreciation on the SCRs based on an end of life of 2031 versus the 2038 end of life reflected in the approved 2019 Depreciation Study. From a technical application, the depreciation expense adjustment presented in the pro

forma reflects the change in the straight-line depreciation of the remaining net book value over a revised estimated useful life. This adjustment results in a reduction to pre-tax operating income of $117,000 (*see* SFR Schedule C-2, page 16, column 48).

25. Include and Annualize Four Corners SCR Deferral Amortization

Q. PLEASE EXPLAIN THE OPERATING INCOME PRO FORMA ADJUSTMENTS FOR THE FOUR CORNERS SELECTIVE CATALYTIC REDUCTION (SCR) DEFERRAL.

A. In relation to the above, APS was authorized in Decision No. 78317 to recover an annual level of amortization of the Four Corners SCR deferral over ten years, through 2031, and to continue deferring costs incurred after December 31, 2020 and through the effective date of new rates as deferrals, and to request recovery for the additional SCRs deferral at the cost of debt established in this rate case.

Therefore, there are two operating income adjustments related to the Four Corners SCR deferral to reflect that which was authorized in Decision No. 78317. The first pro forma adjustment reflects the annual level of amortization that was authorized in Decision No. 78317, since the Test Year only includes seven months of that allowed amortization. The second pro forma adjustment reflects the additional annual level of amortization that the Company is requesting in this case, which is related to the residual amount of Four Corners SCR deferred costs that the Company continued deferring under prior Commission order and Decision No. 78317 up until the December 1, 2021 rate effective date of the decision (amounts deferred from December 31, 2020 through December 1, 2021). APS requests to amortize this residual deferral amount through 2031 to align with the Company's planned exit from the plant. These pro forma adjustments result in a

reduction to pre-tax operating income of $3.4 million and $3.1 million, respectively (*see* SFR Schedule C-2, page 17, columns 49 and 50).

26. Annualize Cholla Inventory

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO INCLUDE CHOLLA INVENTORY.

A. Since the Test Year in this case includes only seven months of authorized cost recovery, this pro forma adjustment is necessary to reflect the annualized level of amortization related to Cholla material and supplies inventory as a result of the anticipated closure of the coal plant and cost recovery of the remaining inventory balance as accepted in Decision No. 78317. This results in a reduction to pre-tax operating income of $310,000 (*see* SFR Schedule C-2, page 17, column 51).

27. Annualize Four Corners Inventory

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO INCLUDE FOUR CORNERS INVENTORY.

A. Similar to the pro forma above, this pro forma adjustment is necessary to reflect the annualized level of amortization related to Four Corners material and supplies inventory as accepted in Decision No. 78317. This results in a reduction to pre-tax operating income of $424,000 (*see* SFR Schedule C-2, page 18, column 52).

28. Normalize Advertising Expense

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO NORMALIZE ADVERTISING EXPENSE.

A. The pro forma normalizes the associated costs of Test Year operations for advertising expense over a three-year period. This results in an increase to pre-tax operating income of $1.7 million (*see* SFR Schedule C-2, page 18, column 53). Please note that advertising costs not normally allowed for ratemaking purposes are excluded from this normalized amount as part of Adjustment 30, described later in my testimony.

29. Include Removal Costs Associated with West Phoenix

Q. PLEASE DESCRIBE THE PRO FORMA TO INCLUDE FOR RECOVERY THE REMOVAL COSTS ASSOCIATED WITH THE CLOSURE AND DECOMMISSIONING OF THE WEST PHOENIX STEAM UNITS.

A. Since the Test Year in this case includes only seven months of authorized cost recovery, this pro forma adjustment is necessary to reflect the annualized level of additional removal costs associated with the closure and subsequent decommissioning of West Phoenix Steam Units as authorized in Decision No. 78317. This adjustment results in a reduction to pre-tax operating income of $416,000 (*see* SFR Schedule C-2, page 18, column 54).

30. Remove Out of Period and Miscellaneous Items

Q. PLEASE DESCRIBE THE PRO FORMA TO REMOVE MISCELLANEOUS AND OUT OF PERIOD ITEMS.

A. In any test year, there are some items recorded that relate to periods other than the Test Year, or conversely, items recorded in other time periods that correctly belong in the Test Year. For the 12 months ended June 30, 2022 (the Test Year), APS is removing costs associated with SCR related legal costs, certain executive compensation, consulting fees, miscellaneous advertising and other general expenses that are not reflective of on-going costs or are costs that APS does not intend to collect from customers. This adjustment, for the sake of simplicity, combines several smaller entries that fit this description and are shown in aggregate in the pro forma. This adjustment results in an increase to pre-tax operating income of $10.3 million (*see* SFR Schedule C-2, page 19, column 55).

31. Include Cloud Computing

Q. PLEASE DESCRIBE THE RATE BASE PRO FORMA ADJUSTMENT TO INCLUDE THE IMPACTS OF CLOUD COMPUTING.

A. As authorized in Decision No. 78317, this rate base pro forma includes the impacts associated with cloud computing in alignment with NARUC's Cloud Computing Resolution (*see* Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements, November 16, 2016) and is calculated by taking the annual level of cloud computing costs associated with applications in which contracts have been entered into and multiplying that by the average contract term of 2.8 years. This pro forma increases rate base by $22.2 million (*see* SFR Schedule B-2, page 3, column 9).

32. Amortize Cholla Unit 2 Regulatory Asset

Q. PLEASE DESCRIBE THE PRO FORMA TO AMORTIZE THE CHOLLA UNIT 2 REGULATORY ASSET.

A. As presented in the Company's last rate case and approved in Decision No. 78317, this pro forma adjustment adjusts the Test Year to reflect the impacts of amortizing the Cholla Unit 2 regulatory asset over the remaining plant life instead of the accelerated method previously approved in Decision No. 76295. Since the Test Year in this case includes only seven months of this authorized level of amortization, this pro forma is necessary to reflect the annualized level of amortization as approved. This adjustment results in an increase to pre-tax operating income of $4.8 million (*see* SFR Schedule C-2, page 19, column 56).

33. Include and Annualize Tax Expense Mechanism (TEAM) Balancing Account Amortization

Q. PLEASE EXPLAIN THE OPERATING INCOME PRO FORMA ADJUSTMENT TO INCLUDE THE AMORTIZATION FOR THE TEAM I, II, AND III BALANCING ACCOUNTS.

A. As presented in APS's last rate case and accepted in Decision No. 78317, this pro forma reflects the annual level of amortization of the TEAM I, II, and III balancing accounts over ten years. Since the Test Year in this case includes only seven months of authorized cost recovery, this pro forma adjustment is necessary to reflect the annualized level of amortization. This pro forma adjustment results in a reduction to pre-tax operating income of $273,000 (*see* SFR Schedule C-2, page 19, column 57).

Q. IS THERE AN ADDITIONAL RELATED OPERATING INCOME PRO FORMA ADJUSTMENT TO INCLUDE THE AMORTIZATION FOR THE TEAM I, II AND III BALANCING ACCOUNTS RESIDUAL AMOUNTS?

A. Yes. The Company is requesting the ability to refund to customers the additional, or residual, amounts of TEAM I, II and III that the Company retained in the balancing account up until the December 1, 2021 rate effective date of Decision No. 78317 (amounts recorded to the balancing account from December 31, 2020 through December 1, 2021). This pro forma adjustment reflects the additional annual level of amortization to be refunded to customers. APS requests to amortize this refund, or benefit to customers, over an eight-year period to align with and be consistent with the related balancing account amortization accepted in Decision No. 78317 for this matter. This pro forma adjustment results in an increase to pre-tax operating income of $604,000 (*see* SFR Schedule C-2, page 20, column 58).

34. Amortize COVID Customer Relief Deferral

Q. PLEASE EXPLAIN THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE COVID CUSTOMER RELIEF DEFERRAL.

A. In Decision No. 77849 (December 17, 2020), APS, among other Arizona electric utilities, was authorized to defer for possible later recovery through rates all customer discounts ordered to be paid less any amounts voluntarily contributed by the utilities from below the line sources. In December 2020, APS applied credits to customer accounts for COVID relief totaling $3.6 million, of which $1.8 million was deferred to a regulatory asset as it represented amounts above what APS committed to fund with shareholder dollars. This pro forma adjustment reflects the annual level of amortization that the Company is requesting to recover over a three-year period and results in a reduction to pre-tax operating income of $600,000 (*see* SFR Schedule C-2, page 20, column 59).

V. ADJUST NUCLEAR DECOMMISSIONING COSTS

Q. PLEASE EXPLAIN THE NUCLEAR DECOMMISSIONING FUNDS AND WHAT IS MEANT BY A "QUALIFYING" DECOMMISSIONING FUND.

A. Like all nuclear power plants, PV eventually will need to be decommissioned, an expensive and time-consuming process. Regulatory agencies throughout the country, including the Commission, have required that the cost of this eventual decommissioning be recovered from electricity customers over the life of the facility.

Most of the amounts collected from customers that relate to decommissioning of a nuclear power plant can be deposited into a "tax-qualified" decommissioning trust. A trust is "tax-qualified" to the extent it meets certain requirements set forth in the Internal Revenue Code and related regulations. A "tax-qualified" decommissioning trust is afforded income tax benefits versus non-tax-qualified

trusts. This favorable tax treatment is twofold. Contributions to a qualified decommissioning trust are deductible for federal income tax purposes in the year made to the extent these do not exceed the "ruling amount" approved by the U.S. Secretary of the Treasury in a private letter ruling. The plant owner must request from the U.S. Secretary of the Treasury a new schedule of ruling amounts upon (1) each renewal of the operating license of the nuclear power plant; (2) any time the taxpayer is authorized by its state regulatory commission to contribute an amount greater than the previously authorized contribution to a tax-qualified trust; or (3) in any event, on the ten-year anniversary of the existing private letter ruling. Secondly, investment earnings of the assets within the trust are taxed at a federal income tax rate of 20% versus 21% if the investment earnings occurred outside of the "tax-qualified" trust. In accordance with the Code of Federal Regulations (CFR) rule, an owner of a nuclear facility is required to select one of three funding methods. The Nuclear Regulatory Commission (NRC) and most state regulators prefer the external funding option, both because of increased security of the funding for its intended purpose and because of the income tax benefits afforded "tax-qualified" decommissioning trusts.

Q. IS THE COMPANY SEEKING AN ADJUSTMENT FOR NUCLEAR DECOMMISSIONING FUNDING AND THE CORRESPONDING EXPENSE?

A. APS is not proposing a change to the total annual amount of funding in the Test Year ($2,281,000); however, the Company is proposing a change to the allocation of the annual funding between the three PV units, with the full amount of funding going to PV Unit 2. Two basic components associated with determining the annual amounts to deposit into the decommissioning fund have changed: earnings assumptions and the decommissioning study cost estimates. While these changes reflect an expected increase in costs and a need for elevated funding levels in PV

Unit 2, a pro forma adjustment is not necessary if Test Year levels are maintained. Commission approval is requested to allow the change in the allocation of the funding amongst the three PV units as provided in Attachment EAB-02DR. The revised decommissioning funding and expense estimates reflect a 2019 study performed by TLG Services, Inc., in which the decommissioning costs are presented in 2019 dollars. An escalation rate is used to account for the inflation that has occurred since the date of the decommissioning cost study and reflects expected increases in decommissioning costs.

Q. PLEASE EXPLAIN THE COMPANY'S PLAN FOR DECOMMISSIONING CONTRIBUTIONS TO PV UNITS 1, 2, AND 3.

A. The Company is requesting at this time that contributions to PV Units 1 and 3 be temporarily suspended. Under the sale leaseback agreement the PV Unit 2 trust is to be fully funded and can only be invested in fixed income securities. Since the yield on fixed income is relatively low compared to the assumed rate of escalation in decommissioning costs, there is a possibility that the earnings of the PV Unit 2 trust will be unable to keep pace with the escalation in decommissioning costs, resulting in the PV Unit 2 trust falling below its fully funded status. To reduce the possibility of this event, the Company is requesting that all of the currently approved decommissioning contributions be allocated to PV Unit 2.

Q. HOW DO THE ASSUMED EARNINGS AND ESCALATION RATES COMPARE?

A. The targeted asset allocation of PV Unit 1 and PV Unit 3 is 60% equities and 40% fixed income. APS continues to propose using a 60% equity and a 40% fixed income asset allocation for PV Units 1 and 3 up until five years prior to decommissioning. Using this asset allocation, an after-tax earnings assumption of 4.33% for PV Units 1 and 3 was employed up to five years prior to each Unit's respective license expiration date and 2.35% rate of return reflecting a 100% fixed

income allocation was assumed thereafter. APS is also proposing to use an after-tax earnings assumption of 2.35% for PV Unit 2. The assumed escalation rate in decommissioning costs is 4%. The earnings assumption for PV Units 1 and 3 was determined using pre-tax investment return assumptions for fixed income of 3.00% for the "tax-qualified" trusts and 2.40% for the "non-tax-qualified" trusts and pre-tax equity returns of 7.40%. The Company did not assume an equity return for the PV Unit 2 trusts due to the investment restrictions included in the terms of the sale leaseback agreement, which prohibit PV Unit 2 from holding equities after January 31, 2010. Therefore, the after-tax earnings assumption for PV Unit 2 is 2.35%.

Q. IS SPECIFIC COMMISSION ACTION REQUIRED?

A. Yes. As previously stated, to continue to receive a full tax deduction for contributions, the owner of a nuclear power plant must request a new schedule of ruling amounts from the U.S. Secretary of the Treasury any time the owner is authorized by its state regulatory commission to contribute an amount greater than the previously authorized contribution to a tax-qualified trust. In this instance the Company is asking to increase the funding to PV Unit 2. Treasury Regulation Section 1.468A-3 states that in the private letter ruling process, the applicant has the burden of proving that the proposed schedule of ruling amounts is consistent with the principles of the decommissioning fund provisions, and that it is based on reasonable assumptions. The Regulation goes on to state: "If a public utility commission established or approved the currently applicable rates for the furnishing or sale by the taxpayer of electricity from the plant, the taxpayer can generally satisfy this burden of proof by demonstrating that the schedule of ruling amounts is calculated using the assumptions used by the public utility commission in its most recent order."

Q. WHAT LANGUAGE DOES APS REQUEST BE INCLUDED IN THE COMMISSION'S FINAL ORDER EVIDENCING APPROVAL OF THE COMPANY'S NUCLEAR DECOMMISSIONING CONTRIBUTIONS?

A. The Company requests that the Commission include the following specific language in their final decision:

> "The decommissioning costs as recommended by APS are adopted as set forth in the decommissioning contribution schedule at Appendix X to this Decision."

Q. IF THE COMMISSION GRANTS THE COMPANY'S REQUEST, WILL THAT RESULT IN DECOMMISSIONING TRUSTS THAT ARE ALL FULLY FUNDED?

A. No. As stated earlier in my testimony, APS is proposing at this time to keep the funding level the same as that reflected in the Test Year levels at $2,281,000, but with a different allocation of funding to each of the three PV units. However, this funding level is not sustainable under the capital market, decommissioning cost, and decommissioning escalation assumptions that are currently applicable. The Company and the Commission will need to revisit this issue in future rate proceedings.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Attachment REW–2DR

2019 Depreciation Rate Study



Arizona Public Service Company



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EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for utility plant owned and operated by Arizona Public Service Company (APS). The report contains recommended 2019 depreciation rates and parameters for: a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. Work on the study began in January 2019 and progressed through August, at which time the project was completed.

Foster Associates is a public utility economics consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by APS were approved by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–16–0036 et al. (Decision No. 76295, dated August 18, 2017). Depreciation rates initially requested by APS were developed in a 2016 Depreciation Rate Study conducted by Foster Associates. The recommended composite accrual rate of 2.99 percent produced a 2016 annualized accrual of $396,201,674 or an increase of $70,971,863 from previously approved rates of 2.45 percent.

Foster Associates was subsequently requested to develop a set of accrual rates that would produce a reduction of approximately $29 million in 2016 annualized depreciation expense from the filed expense of $396,201,674. The following adjustments were made to the filed 2016 study to achieve a reduction of $29,113,093:

- Projection life for Account 369.00 (Services) extended from 45 years (L1 dispersion) to 55 years (L1 dispersion).
- Future net salvage rate for Account 364.01 (Poles, Towers and Fixtures – Wood) reduced from –25 percent to –10 percent.
- Future net salvage rate for Account 365.00 (Overhead Conductors and Devices) reduced from –25 percent to –10 percent.

- Future net salvage rate for Account 369.00 (Services) reduced from –50 percent to –20 percent.
- Future net salvage rate for Account 373.00 (Street Lighting and Signal Systems) increased from –5 percent to –12 percent.
- Palo Verde reserve imbalance (*i.e.*, $435,409,053 excess) amortized over 12 years rather than remaining lives of approximately 29 years.

The composite accrual rate of 2.77 percent resulting from the above adjustments produced a 2016 annualized accrual of $367,088,581, or a reduction of $29,113,093 from the initially filed accrual of $396,201,674. The adjusted rates were adopted in the Settlement and approved by the ACC in Decision No. 76295.

The principal findings and recommendations developed in the current study are summarized in Section IV of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides a computation of the estimated future net salvage rate for steam production facilities. Statement G contains the computation of terminal dismantlement costs for steam production and solar facilities. Statement H provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains current and proposed statistics including average service life, average remaining life, and average net salvage rates.

The Settlement Agreement approved by the ACC in Docket No. E–01345A–16–0036 et al. provided, inter alia, that:

> "In APS's next rate case, APS will file a depreciation rate study that includes alternative calculations for cost of removal and dismantlement (negative net salvage) using the 'FAS 143' discounted net present value method, computed using a discount rate to be agreed upon."[1]

In compliance with this directive, Section IV of this report also contains a set of statements providing accrual rates, annualized accruals, depreciation reserves, net salvage rates and parameters derived from an SFAS 143 formulation of accrual rates for net salvage.

[1] Decision No. 76295 (August 18. 2017), Exhibit A, Paragraph 6.6.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Field visits and discussions with APS operations and plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been approved, APS is currently using a depreciation system composed of the straight–line method, vintage group procedure and remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

Depreciation theory provides that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains ap-

propriate for the approved amortization categories.

PROPOSED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the current study.

Function	Accrual Rate			2019 Annualized Accrual		
	Current	Proposed	Diff.	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.59%	5.02%	1.43%	$ 73,467,101	$ 102,807,136	$ 29,340,035
Nuclear	0.90%	0.96%	0.06%	26,538,968	28,470,493	1,931,525
Other	3.73%	4.00%	0.27%	120,526,363	129,300,016	8,773,653
Transmission	2.01%	2.01%		2,746,897	2,761,160	14,263
Distribution	2.31%	2.51%	0.20%	145,675,247	157,904,801	12,229,554
General Plant	6.31%	6.14%	-0.17%	59,170,196	57,485,130	(1,685,066)
Total	2.74%	3.07%	0.33%	$ 428,124,772	$ 478,728,736	$ 50,603,964

Table 1. Current vs Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.07 percent. Depreciation expense is currently accrued at rates that composite to 2.74 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.33 percentage points.

A continued application of current rates would produce annualized depreciation expense of $428,124,772 compared with an annualized expense of $478,728,736 using the rates developed in this study. The proposed 2019 expense increase is $50,603,964. The computed change in annualized accruals includes a reduction of $28,419,146 attributable to an amortization of a $490,198,765 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2019 study.

Of the 188 plant accounts included in the study, Foster Associates is recommending rate reductions for 45 accounts, increases for 137 accounts and no change for 6 accounts.

In compliance with the directive in Docket No. E–01345A–16–0036, Table 2 below provides a summary of annual rates and accruals derived from an application of the service life parameters developed in the 2019 study combined with an SFAS 143 formulation of accruals for future net salvage.

Function	Accrual Rate			2019 Annualized Accrual		
	Current	SFAS 143	Diff.	Current	SFAS 143	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.59%	4.93%	1.34%	$ 73,467,101	$ 100,856,998	$ 27,389,897
Nuclear	0.90%	1.00%	0.10%	26,538,968	29,699,623	3,160,655
Other	3.73%	3.95%	0.22%	120,526,363	127,485,476	6,959,113
Transmission	2.01%	1.97%	-0.04%	2,746,897	2,704,116	(42,781)
Distribution	2.31%	2.45%	0.14%	145,675,247	153,978,945	8,303,698
General Plant	6.31%	6.13%	-0.18%	59,170,196	57,401,013	(1,769,183)
Total	2.74%	3.02%	0.28%	$ 428,124,772	$ 472,126,171	$ 44,001,399

Table 2. Current vs SFAS 143 Rates and Accruals

SFAS 143 accrual rates for net salvage would produce primary account depreciation rates equivalent to a composite rate of 3.02 percent. Depreciation expense is currently accrued at rates that composite to 2.74 percent. The resulting change in the composite depreciation rate would be an increase of 0.28 percentage points.

A continued application of current rates would produce annualized depreciation expense of $428,124,772 compared with an annualized expense of $472,126,171 using SFAS 143 accrual rates for net salvage. The resulting 2019 expense increase would be $44,001,399.

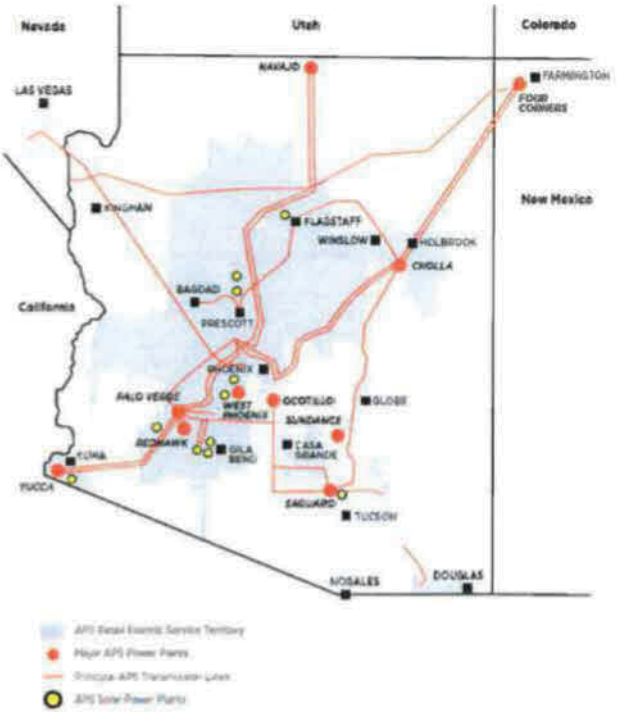
Of the 188 plant accounts included in the study, a SFAS 143 formulation of accrual rates for net salvage would produce rate reductions for 67 accounts, increases for 116 accounts and no change for 5 accounts.

COMPANY PROFILE

GENERAL

Arizona Public Service Company is the largest subsidiary of Pinnacle West Capital Corporation. APS provides electric service to more than 1.2 million customers in 11 of Arizona's 15 counties mainly concentrated in northern and central Arizona. Pinnacle West owns all of the outstanding common stock of APS.

Incorporated in 1920 under the laws of the state of Arizona, APS employs more than 6,400 employees, including employees at jointly–owned generating facilities for which APS serves as the generating facility manager.



TRANSMISSION AND DISTRIBUTION FACILITIES

Transmission facilities consist of approximately 6,192 pole miles of overhead lines and approximately 49 miles of underground lines, 5,969 miles of which are located in Arizona. APS projects it will develop 275 miles of new transmission lines over the next ten years. APS shares ownership of some of its transmission facilities with other companies.

Distribution facilities consist of approximately 11,194 miles of overhead lines and approximately 21,854 miles of underground primary cable, all of which are located in Arizona.

GENERATING RESOURCES

In addition to the Palo Verde Nuclear Generating Station, APS owns and operates six natural–gas plants, one oil plant, two coal–fired plants, and an increasing array of renewable energy power generation. APS's portfolio of owned and leased generating facilities is provided in Table 3 below.

Table 3. Generation Facilities

Name	No. of Units	% Owned (a)	Principal Fuels Used	Primary Dispatch Type	Owned Capacity (MW)
Nuclear:					
Palo Verde (b)	3	29.1%	Uranium	Base Load	1,146
Total Nuclear					1,146
Steam:					
Four Corners 4, 5 (c)	2	63%	Coal	Base Load	970
Cholla 1,3	2		Coal	Base Load	387
Navajo (d)	3	14%	Coal	Base Load	315
Ocotillo (e)	—		Gas	Peaking	—
Total Steam					1,672
Combined Cycle:					
Redhawk	2		Gas	Load Following	984
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,871
Combustion Turbine:					
Ocotillo (e)	2		Gas	Peaking	110
Saguaro	3		Gas	Peaking	189
Douglas/Fairview	1		Oil	Peaking	16
Sundance	10		Gas	Peaking	420
West Phoenix	2		Gas	Peaking	110
Yucca 1, 2, 3	3		Gas	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	96
Total Combustion Turbine					1,088
Solar:					
Cotton Center (f)	1		Solar	As Available	17
Hyder I (f)	1		Solar	As Available	16
Paloma (f)	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	19
Gila Bend (f)	1		Solar	As Available	32
Hyder II (f)	1		Solar	As Available	14
Foothills (f)	1		Solar	As Available	35
Luke AFB	1		Solar	As Available	10
Desert Star (f)	1		Solar	As Available	10
Red Rock	1		Solar	As Available	40
APS Owned Distributed Energy			Solar	As Available	24
Multiple facilities			Solar	As Available	4
Total Solar					238
Total Capacity					6,015

(a) 100% unless otherwise noted.

(b) The other participants are Salt River Project (17.49%), SCE (15.8%), El Paso (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water & Power (5.7%). The plant is operated by APS.

(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), Tucson Electric Power Company (7%) and NTEC (7%). The plant is operated by APS.

(d) The other participants are Salt River Project (42.9%), Nevada Power Company (11.3%), the United States Government (24.3%) and Tucson Electric Power Company (7.5%). The plant is operated by Salt River Project. In July 2016, Salt River Project purchased Los Angeles Department of Water & Power's share in this plant (21.2%).

(e) Ocotillo Steam Units 1 and 2 were retired on January 10, 2019. Units 3 through 7 are expected to go into service by the middle of 2019 and will increase generation capacity by 510 MW.

(f) APS is under contract to add battery storage at these AZ Sun sites and anticipates such storage facilities could be in service by mid-2020.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation rates used by APS for its steam, nuclear, other production, transmission, distribution and general plant categories. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2019 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribu-

tion to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by APS provides aged transactions for all plant accounts.

Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1971 through 2018. Detailed accounting transactions were extracted from the CPR system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The database used in conducting the 2016 study was updated for the current study by appending additional plant and net salvage transactions for activity years 2016–2018 and age distributions of surviving plant at December 31, 2018. The accuracy and completeness of the assembled database was verified for activity years 2016 through 2018 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2016 were verified in the 2016 study. Age distributions of surviving plant at December 31, 2018 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2018 were used in the 2019 study to derive appropriate net salvage rates. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected

remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

Analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2019 study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio—called a "retirement ratio"—is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves, which are mathematically described by the Pearson frequency curve family. Observed life tables were

smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life for each plant account. The observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family (using the projection life derived from the polynomial hazard function) to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), retirement dispersion is also exhibited in plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are viewed as "interim" retirements that will be replaced in order to maintain the integrity of the system. Plant facilities may also be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method with interim retirements described by an appropriate survivor curve. All plant accounts classified in Steam, Nuclear and Other Production were identified by unit and treated as life–span categories in the 2019 study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

A. TRADITIONAL METHOD (STRAIGHT–LINE)

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Independent contractors were retained by APS between 2013 and 2015 to develop cost estimates for the demolition and abatement of steam and other production units. Costs estimated for dismantling these units were used in the current depreciation study to formulate average and future net salvage rates. Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for these production facilities.[2]

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the

[2]The firm of Burns & McDonnell was retained in 2013 to conduct a decommissioning cost study of generation assets located at Cholla, Ocotillo and Saguaro. The firm was retained in 2014 to conduct a decommissioning cost evaluation for Foothills Solar Plant and in 2015 to conduct a cost evaluation for Luke Solar Plant and Desert Star Solar Plant.

Shaw Environmental Inc. was retained by Arizona Public Service Company to estimate demolition costs in 2015 dollars for the Four Corners Generating Station of which APS holds 63 percent ownership interest in Units 4 and 5, and 63 percent ownership of Common Facilities.

estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2019 study for transmission, distribution and general plant categories to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of estimated average net salvage rates is shown in Statement E.

B. SFAS 143 METHOD

The SFAS 143 method of accruing for net savage was modeled in the current study by first estimating the present value of non–legal asset retirement obligations (AROs). Present values were derived by discounting the product of future retirements and future net salvage rates estimated in the traditional net salvage analysis.[3] Future retirements for each vintage were derived from an application of survivor ratios to the age distributions of surviving plant at December 31, 2018. Survivor ratios were derived from the projection lives and curves estimated in the statistical life analysis. The present value of the non–legal AROs was accreted and added to straight–line, whole–life accruals of estimated asset retirement costs (ARCs) to obtain a total accrual for net salvage.

ARC investments were derived by discounting the present value of estimated AROs to the installation date of each vintage. ARC reserves were obtained by multiplying derived ARCs by the compliment of theoretical net book ratios (*i.e.* the ratio of remaining life to average service life). Cumulative accretion was derived as the difference between estimated AROs and ARCs. The sum of ARC reserves and cumulative accretion is the theoretical net salvage reserve. Theoretical investment reserves were obtained by multiplying plant in service by the compliment of theoretical net book ratios.

[3] A discount rate of 3.78 percent was used in the analysis.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

Survivor curves used in the calculation of theoretical depreciation reserves are intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences can also arise from plant accounting activity such as transfers and adjustments that may require an identification of reserves at a level lower than maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based

upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is again appropriate for APS. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current study) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant categories was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserves (net of amortizable accounts) to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

Table 4 below contains a summary of recorded and computed reserves at December 31, 2018 for the alternative methods of accruing for net salvage considered in this study.

		Recorded Reserve		Computed Reserve		
Method	Plant	Amount	Ratio	Amount	Ratio	Imbalance
A	B	C	D=C/B	E	F=E/B	G=C-E
Straight-Line	$15,618,730,997	$5,443,951,822	34.86%	$4,953,753,056	31.72%	$490,198,766
SFAS 143	15,618,730,997	5,443,951,822	34.86%	4,850,479,818	31.06%	593,472,004

Table 4. Recorded and Computed Reserves (December 31, 2018)

With the exception of Palo Verde, a proportionate amount of the measured reserve imbalances (Column G) would be amortized over the composite weighted–average remaining life of each rate category using the remaining–life depreciation rates developed for each alternative. Consistent with the settlement agreement in Docket No. E–01345A–16–0036 et al., measured reserve imbalances for Palo Verde are amortized over a period of nine years in the current study. A comparison of recorded, computed and redistributed reserves for each of the alternative methods of accruing for net salvage is contained in Section IV, Statement C.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service

units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2019 study were developed using the currently approved system composed of the straight–line method, vintage group procedure and remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure and whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that this system will remain appropriate for APS, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for APS.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after 2019 retirements have been recorded. Amortization rates shown in Statement A (Column G) have been applied to year–end 2018 plant balances to derive 2019 annualized accruals. Applying a reciprocally–derived rate to plant balances prior to posting retirements would overstate 2019 annualized amortization expense.

The SFAS 143 treatment of accruing for net salvage is formulated as the sum of straight–line accruals for asset retirement costs and accretion of asset retirement obligations using the vintage group procedure, remaining–life technique. The investment portion of depreciation accruals is derived using the straight–line method, vintage group procedure, remaining–life technique.

The computation of a SFAS 143 formulation of accrual rates for net salvage is shown in Statement D. Future net salvage rates (Sf) that could be used in a straight–line, remaining–life formulation of depreciation rates to produce rates equivalent to the sum of investment and net salvage accrual rates shown in Statement A are presented in Statement E, Column M.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and current and proposed service life and net salvage parameters recommended for a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. The content of the statements developed for the straight–line method of accruing for net salvage is briefly described below:

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2019 depreciation accruals based upon the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2018.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a computation of the estimated future net salvage rate for steam production facilities.
- Statement G contains the computation of terminal dismantlement costs for steam production facilities.
- Statement H provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by the Company for the mix of investments recorded on December 31, 2018. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

Statements developed for the SFAS 143 method of accruing for net salvage are described as follows:

- Statement A provides a comparative summary of current and SFAS 143 annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and SFAS 143 annualized 2019 depreciation accruals based upon the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2018.
- Statement D provides the derivation of SFAS 143 net salvage accrual rates.
- Statement E provides a comparative summary of current and SFAS 143 parameters and statistics used in the formulation of depreciation rates.

Straight–Line

Statements A through H

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	5.01%	0.39%	5.40%	5.77%	0.44%	6.21%
312.00 Boiler Plant Equipment	2.90%	0.33%	3.23%	4.41%	0.44%	4.85%
314.00 Turbogenerator Units	3.63%	0.36%	3.99%	4.86%	0.47%	5.33%
315.00 Accessory Electric Equipment	4.26%	0.41%	4.67%	4.91%	0.40%	5.31%
316.00 Miscellaneous Power Plant Equipment	3.80%	0.43%	4.23%	4.58%	0.40%	4.98%
Total Steam Production Plant	3.24%	0.35%	3.59%	4.58%	0.44%	5.02%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	0.98%	0.01%	0.99%	1.14%	0.01%	1.15%
322.00 Reactor Plant Equipment	0.76%	0.06%	0.82%	0.71%	0.07%	0.78%
323.00 Turbogenerator Units	0.89%	0.03%	0.92%	1.03%		1.03%
324.00 Accessory Electric Equipment	0.39%	0.01%	0.40%	0.42%	0.01%	0.43%
325.00 Miscellaneous Power Plant Equipment	1.39%	0.05%	1.44%	1.66%	0.04%	1.70%
Total Nuclear Production Plant	0.86%	0.04%	0.90%	0.92%	0.04%	0.96%
OTHER PRODUCTION						
341.00 Structures and Improvements	3.53%	0.25%	3.78%	3.88%	0.37%	4.25%
342.00 Fuel Holders, Products and Accessories	3.60%	0.18%	3.78%	3.91%	0.21%	4.12%
343.00 Prime Movers	3.29%	0.15%	3.44%	3.57%	0.23%	3.80%
344.00 Generators and Devices	3.70%	0.07%	3.77%	3.86%	0.14%	4.00%
345.00 Accessory Electric Equipment	3.74%	0.23%	3.97%	3.94%	0.31%	4.25%
346.00 Miscellaneous Power Plant Equipment	3.95%	0.20%	4.15%	4.61%	0.27%	4.88%
Total Other Production Plant	3.62%	0.11%	3.73%	3.82%	0.18%	4.00%
TRANSMISSION PLANT						
352.02 Structures and Improvements	2.51%		2.51%	2.66%		2.66%
353.00 Station Equipment	1.91%	0.09%	2.00%	1.92%	0.09%	2.01%
354.00 Towers and Fixtures	1.78%		1.78%	1.80%		1.80%
355.00 Poles and Fixtures	1.85%	0.37%	2.22%	1.86%	0.37%	2.23%
356.00 Overhead Conductors and Devices	1.74%	0.33%	2.07%	1.76%	0.33%	2.09%
Total Transmission Plant	1.91%	0.10%	2.01%	1.92%	0.09%	2.01%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.58%	0.08%	1.66%	1.62%	0.16%	1.78%
362.00 Station Equipment	2.20%	0.08%	2.28%	2.16%	0.09%	2.25%
363.00 Storage Battery Equipment	8.79%		8.79%	9.81%	0.25%	10.06%
364.01 Poles, Towers and Fixtures - Wood	2.10%	0.19%	2.29%	2.16%	0.43%	2.59%
364.02 Poles, Towers and Fixtures - Steel	1.95%	0.19%	2.14%	1.97%	0.19%	2.16%
365.00 Overhead Conductors and Devices	1.92%	0.20%	2.12%	1.96%	0.40%	2.36%
366.00 Underground Conduit	1.57%	0.17%	1.74%	1.61%	0.25%	1.86%
367.00 Underground Conductors and Devices	2.34%	0.20%	2.54%	2.41%	0.33%	2.74%
368.00 Line Transformers	1.70%	0.06%	1.76%	1.75%	0.07%	1.82%
369.00 Services	1.68%	0.33%	2.01%	1.74%	0.35%	2.09%
370.01 Meters - Electronic	5.52%	-0.03%	5.49%	5.96%	-0.03%	5.93%
370.03 Meters - AMI	4.84%		4.84%	6.22%		6.22%
371.00 Installations on Customers' Premises	2.11%	0.31%	2.42%	2.15%	0.31%	2.46%
373.00 Street Lighting and Signal Systems	1.72%	0.18%	1.90%	1.77%	0.24%	2.01%
Total Distribution Plant	2.15%	0.16%	2.31%	2.27%	0.24%	2.51%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.52%	0.17%	2.69%	2.50%	0.27%	2.77%
391.CM Office Furn. and Equip. - Computer	12.86%	0.02%	12.88%	12.15%	0.06%	12.21%
397.00 Communication Equipment	4.83%		4.83%	4.72%	0.02%	4.74%
Total Depreciable	6.50%	0.06%	6.56%	6.24%	0.11%	6.35%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Amortizable						
391.FE Office Furn. and Equip. - Furniture	← 20 Year Amortization →			← 20 Year Amortization →		
393.00 Stores Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
395.00 Laboratory Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
398.00 Miscellaneous Equipment	← 24 Year Amortization →			← 24 Year Amortization →		
Total Amortizable	4.84%		4.84%	4.84%		4.84%
Total General Plant	6.26%	0.05%	6.31%	6.04%	0.10%	6.14%
TOTAL UTILITY	2.60%	0.14%	2.74%	2.86%	0.21%	3.07%
STEAM PRODUCTION (by Unit)						
Cholla						
311.00 Structures and Improvements	7.05%	0.50%	7.55%	8.11%	0.63%	8.74%
312.00 Boiler Plant Equipment	7.01%	0.58%	7.59%	7.97%	0.64%	8.61%
314.00 Turbogenerator Units	6.63%	0.45%	7.08%	7.39%	0.50%	7.89%
315.00 Accessory Electric Equipment	6.12%	0.44%	6.56%	6.99%	0.50%	7.49%
316.00 Miscellaneous Power Plant Equipment	7.29%	0.55%	7.84%	8.51%	0.63%	9.14%
Total Cholla	6.90%	0.54%	7.44%	7.85%	0.61%	8.46%
Cholla Unit 1						
311.00 Structures and Improvements	5.36%	0.44%	5.80%	5.79%	0.47%	6.26%
312.00 Boiler Plant Equipment	6.04%	0.65%	6.69%	6.67%	0.71%	7.38%
314.00 Turbogenerator Units	6.37%	0.58%	6.95%	6.85%	0.62%	7.47%
315.00 Accessory Electric Equipment	5.48%	0.48%	5.96%	5.91%	0.51%	6.42%
316.00 Miscellaneous Power Plant Equipment	5.15%	0.45%	5.60%	6.73%	0.56%	7.29%
Total Cholla Unit 1	6.02%	0.61%	6.63%	6.62%	0.66%	7.28%
Cholla Unit 3						
311.00 Structures and Improvements	7.02%	0.46%	7.48%	7.94%	0.52%	8.46%
312.00 Boiler Plant Equipment	7.28%	0.55%	7.83%	8.33%	0.61%	8.94%
314.00 Turbogenerator Units	6.72%	0.39%	7.11%	7.63%	0.44%	8.07%
315.00 Accessory Electric Equipment	5.99%	0.42%	6.41%	6.79%	0.48%	7.27%
316.00 Miscellaneous Power Plant Equipment	7.24%	0.52%	7.76%	8.37%	0.62%	8.99%
Total Cholla Unit 3	7.05%	0.51%	7.56%	8.05%	0.57%	8.62%
Cholla Common						
311.00 Structures and Improvements	7.19%	0.52%	7.71%	8.33%	0.67%	9.00%
312.00 Boiler Plant Equipment	7.27%	0.60%	7.87%	8.32%	0.67%	8.99%
314.00 Turbogenerator Units	8.50%	0.63%	9.13%	8.30%	0.59%	8.89%
315.00 Accessory Electric Equipment	7.29%	0.47%	7.76%	8.92%	0.58%	9.50%
316.00 Miscellaneous Power Plant Equipment	7.89%	0.59%	8.48%	9.06%	0.66%	9.72%
Total Cholla Common	7.31%	0.56%	7.87%	8.43%	0.67%	9.10%
Four Corners						
311.00 Structures and Improvements	2.52%	0.25%	2.77%	2.92%	0.19%	3.11%
312.00 Boiler Plant Equipment	1.47%	0.25%	1.72%	3.16%	0.37%	3.53%
314.00 Turbogenerator Units	1.59%	0.30%	1.89%	3.14%	0.44%	3.58%
315.00 Accessory Electric Equipment	2.72%	0.39%	3.11%	3.19%	0.32%	3.51%
316.00 Miscellaneous Power Plant Equipment	2.36%	0.38%	2.74%	2.96%	0.31%	3.27%
Total Four Corners	1.62%	0.26%	1.88%	3.14%	0.37%	3.51%
Four Corners Units 4-5						
311.00 Structures and Improvements	1.75%	0.31%	2.06%	2.05%	0.19%	2.24%
312.00 Boiler Plant Equipment	1.40%	0.24%	1.64%	3.14%	0.37%	3.51%
314.00 Turbogenerator Units	1.55%	0.30%	1.85%	3.13%	0.45%	3.58%
315.00 Accessory Electric Equipment	2.12%	0.41%	2.53%	2.60%	0.32%	2.92%
316.00 Miscellaneous Power Plant Equipment	2.02%	0.40%	2.42%	2.50%	0.28%	2.78%
Total Four Corners Units 4-5	1.47%	0.26%	1.73%	3.07%	0.37%	3.44%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Four Corners Common						
311.00 Structures and Improvements	3.81%	0.16%	3.97%	4.36%	0.18%	4.54%
312.00 Boiler Plant Equipment	3.44%	0.44%	3.88%	3.78%	0.38%	4.16%
314.00 Turbogenerator Units	2.87%	0.27%	3.14%	3.45%	0.25%	3.70%
315.00 Accessory Electric Equipment	3.93%	0.36%	4.29%	4.38%	0.33%	4.71%
316.00 Miscellaneous Power Plant Equipment	3.03%	0.34%	3.37%	3.87%	0.37%	4.24%
Total Four Corners Common	3.52%	0.34%	3.86%	4.03%	0.32%	4.35%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	0.98%	0.01%	0.99%	1.85%	-0.70%	1.15%
322.00 Reactor Plant Equipment	0.76%	0.06%	0.82%	0.71%	0.07%	0.78%
323.00 Turbogenerator Units	0.89%	0.03%	0.92%	1.03%		1.03%
324.00 Accessory Electric Equipment	0.39%	0.01%	0.40%	0.42%	0.01%	0.43%
325.00 Miscellaneous Power Plant Equipment	1.39%	0.05%	1.44%	1.66%	0.04%	1.70%
Total Palo Verde	0.86%	0.04%	0.90%	0.92%	0.04%	0.96%
Palo Verde Unit 1						
321.00 Structures and Improvements	0.18%		0.18%	0.30%	0.01%	0.31%
322.00 Reactor Plant Equipment	0.60%	0.01%	0.61%	0.56%	0.02%	0.58%
323.00 Turbogenerator Units	0.79%	0.05%	0.84%	0.98%	0.08%	1.06%
324.00 Accessory Electric Equipment	0.19%		0.19%	0.23%	0.01%	0.24%
325.00 Miscellaneous Power Plant Equipment	0.40%	0.04%	0.44%	0.56%	0.03%	0.59%
Total Palo Verde Unit 1	0.49%	0.01%	0.50%	0.53%	0.03%	0.56%
Palo Verde Unit 2						
321.00 Structures and Improvements	0.37%		0.37%	0.33%	0.01%	0.34%
322.00 Reactor Plant Equipment	0.96%	0.06%	1.02%	0.88%	0.06%	0.94%
323.00 Turbogenerator Units	1.11%	0.03%	1.14%	1.10%	0.05%	1.15%
324.00 Accessory Electric Equipment	0.47%	0.01%	0.48%	0.45%	0.01%	0.46%
325.00 Miscellaneous Power Plant Equipment	0.69%	0.03%	0.72%	0.60%	0.03%	0.63%
Total Palo Verde Unit 2	0.81%	0.04%	0.85%	0.76%	0.04%	0.80%
Palo Verde Unit 3						
321.00 Structures and Improvements	0.29%		0.29%	0.22%		0.22%
322.00 Reactor Plant Equipment	0.81%	0.09%	0.90%	0.72%	0.10%	0.82%
323.00 Turbogenerator Units	0.81%	0.01%	0.82%	0.98%	-0.09%	0.89%
324.00 Accessory Electric Equipment	0.39%	0.01%	0.40%	0.36%	0.02%	0.38%
325.00 Miscellaneous Power Plant Equipment	0.55%	0.04%	0.59%	0.50%	0.04%	0.54%
Total Palo Verde Unit 3	0.66%	0.05%	0.71%	0.63%	0.03%	0.66%
Palo Verde Water Reclamation						
321.00 Structures and Improvements	2.05%	0.03%	2.08%	2.35%	0.02%	2.37%
322.00 Reactor Plant Equipment	2.92%	0.04%	2.96%	3.04%	0.04%	3.08%
323.00 Turbogenerator Units	1.43%	0.17%	1.60%	1.67%	0.14%	1.81%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	2.19%	0.01%	2.20%	2.67%	3.63%	6.30%
Total Palo Verde Water Reclamation	2.05%	0.03%	2.08%	2.35%	0.02%	2.37%
Palo Verde Common						
321.00 Structures and Improvements	1.31%	0.02%	1.33%	1.61%	0.03%	1.64%
322.00 Reactor Plant Equipment	0.98%	0.42%	1.40%	1.30%	0.45%	1.75%
323.00 Turbogenerator Units	2.31%	0.24%	2.55%	2.42%	0.17%	2.59%
324.00 Accessory Electric Equipment	1.08%	0.01%	1.09%	1.39%	0.02%	1.41%
325.00 Miscellaneous Power Plant Equipment	1.94%	0.06%	2.00%	2.37%	0.04%	2.41%
Total Palo Verde Common	1.50%	0.07%	1.57%	1.85%	0.07%	1.92%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
OTHER PRODUCTION						
Combined Cycle						
341.00 Structures and Improvements	4.00%	0.20%	4.20%	3.78%	0.21%	3.99%
342.00 Fuel Holders, Products and Accessories	4.37%	0.23%	4.60%	4.13%	0.22%	4.35%
343.00 Prime Movers	3.97%	0.26%	4.23%	3.81%	0.21%	4.02%
344.00 Generators and Devices	4.33%	-0.11%	4.22%	4.58%	-0.04%	4.54%
345.00 Accessory Electric Equipment	3.97%	0.19%	4.16%	4.86%	0.32%	5.18%
346.00 Miscellaneous Power Plant Equipment	4.41%	0.20%	4.61%	4.89%	0.30%	5.19%
Total Combined Cycle	3.99%	0.05%	4.04%	4.37%	0.07%	4.44%
Redhawk CC Units 1-2						
341.00 Structures and Improvements	4.00%	0.20%	4.20%	4.10%	0.20%	4.30%
342.00 Fuel Holders, Products and Accessories	4.37%	0.23%	4.60%	4.64%	0.27%	4.91%
343.00 Prime Movers	3.97%	0.26%	4.23%	4.09%	0.28%	4.37%
344.00 Generators and Devices	4.33%	-0.11%	4.22%	4.69%	-0.18%	4.51%
345.00 Accessory Electric Equipment	3.97%	0.19%	4.16%	4.32%	0.33%	4.65%
346.00 Miscellaneous Power Plant Equipment	4.41%	0.20%	4.61%	4.61%	0.20%	4.81%
Total Redhawk CC Units 1-2	4.22%	0.01%	4.23%	4.51%	-0.02%	4.49%
West Phoenix						
341.00 Structures and Improvements	2.90%	0.21%	3.11%	3.59%	0.21%	3.80%
342.00 Fuel Holders, Products and Accessories	3.76%	0.19%	3.95%	3.91%	0.20%	4.11%
343.00 Prime Movers	3.42%	0.14%	3.56%	3.56%	0.14%	3.70%
344.00 Generators and Devices	3.86%	0.02%	3.88%	4.46%	0.11%	4.57%
345.00 Accessory Electric Equipment	4.66%	0.30%	4.96%	5.19%	0.32%	5.51%
346.00 Miscellaneous Power Plant Equipment	4.55%	0.23%	4.78%	5.04%	0.33%	5.37%
Total West Phoenix	3.77%	0.09%	3.86%	4.24%	0.15%	4.39%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	4.03%	0.19%	4.22%	4.21%	0.21%	4.42%
342.00 Fuel Holders, Products and Accessories	3.94%	0.20%	4.14%	3.75%	0.19%	3.94%
343.00 Prime Movers						
344.00 Generators and Devices	4.00%	0.14%	4.14%	4.97%	0.24%	5.21%
345.00 Accessory Electric Equipment	5.21%	0.35%	5.56%	5.81%	0.37%	6.18%
346.00 Miscellaneous Power Plant Equipment	4.82%	0.23%	5.05%	5.46%	0.41%	5.87%
Total West Phoenix CC Units 1-3	4.23%	0.19%	4.42%	4.99%	0.26%	5.25%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	3.30%	0.17%	3.47%	4.12%	0.21%	4.33%
342.00 Fuel Holders, Products and Accessories	3.21%	0.16%	3.37%	3.32%	0.17%	3.49%
343.00 Prime Movers	3.21%	0.02%	3.23%	3.25%	0.01%	3.26%
344.00 Generators and Devices	3.80%	0.18%	3.98%	3.87%	0.18%	4.05%
345.00 Accessory Electric Equipment	4.00%	0.20%	4.20%	4.34%	0.22%	4.56%
346.00 Miscellaneous Power Plant Equipment	4.50%	0.22%	4.72%	4.77%	0.20%	4.97%
Total West Phoenix CC Unit 4	3.40%	0.09%	3.49%	3.52%	0.08%	3.60%
West Phoenix CC Unit 5						
341.00 Structures and Improvements	3.48%	0.18%	3.66%	3.74%	0.17%	3.91%
342.00 Fuel Holders, Products and Accessories	3.21%	0.16%	3.37%	6.37%	0.32%	6.69%
343.00 Prime Movers	3.53%	0.20%	3.73%	3.72%	0.22%	3.94%
344.00 Generators and Devices	3.76%	-0.09%	3.67%	4.17%	0.01%	4.18%
345.00 Accessory Electric Equipment	3.52%	0.19%	3.71%	3.91%	0.21%	4.12%
346.00 Miscellaneous Power Plant Equipment	4.12%	0.22%	4.34%	4.38%	0.24%	4.62%
Total West Phoenix CC Unit 5	3.67%	0.03%	3.70%	4.03%	0.09%	4.12%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
West Phoenix Common						
341.00 Structures and Improvements	2.44%	0.24%	2.68%	3.32%	0.24%	3.56%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total West Phoenix Common	2.44%	0.24%	2.68%	3.32%	0.24%	3.56%
Combustion Turbine						
341.00 Structures and Improvements	4.00%	0.20%	4.20%	4.57%	0.52%	5.09%
342.00 Fuel Holders, Products and Accessories	4.37%	0.23%	4.60%	3.30%	0.01%	3.31%
343.00 Prime Movers	3.97%	0.26%	4.23%	3.40%	0.14%	3.54%
344.00 Generators and Devices	4.33%	-0.11%	4.22%	3.42%	0.15%	3.57%
345.00 Accessory Electric Equipment	3.97%	0.19%	4.16%	3.39%	0.04%	3.43%
346.00 Miscellaneous Power Plant Equipment	4.41%	0.20%	4.61%	4.30%	0.10%	4.40%
Total Combustion Turbine	3.27%	0.08%	3.35%	3.45%	0.21%	3.66%
Douglas CT						
341.00 Structures and Improvements	16.13%	0.81%	16.94%	9.06%	0.46%	9.52%
342.00 Fuel Holders, Products and Accessories	24.09%	1.08%	25.17%	9.19%	0.46%	9.65%
343.00 Prime Movers	11.37%	-9.17%	2.20%	8.99%	0.30%	9.29%
344.00 Generators and Devices	18.97%	0.95%	19.92%	9.11%	0.45%	9.56%
345.00 Accessory Electric Equipment	23.54%	1.09%	24.63%	9.08%	0.45%	9.53%
346.00 Miscellaneous Power Plant Equipment	24.08%	1.28%	25.36%	9.19%	0.46%	9.65%
Total Douglas CT	14.46%	-5.82%	8.64%	9.03%	0.35%	9.38%
Ocotillo						
341.00 Structures and Improvements	5.50%	0.48%	5.98%	6.93%	1.44%	8.37%
342.00 Fuel Holders, Products and Accessories	3.72%	0.19%	3.91%	5.51%	0.28%	5.79%
343.00 Prime Movers	5.41%	0.70%	6.11%	6.23%	0.65%	6.88%
344.00 Generators and Devices	3.37%	0.01%	3.38%	3.26%	0.16%	3.42%
345.00 Accessory Electric Equipment	4.84%	0.27%	5.11%	5.60%	0.30%	5.90%
346.00 Miscellaneous Power Plant Equipment	4.18%	0.20%	4.38%	4.95%	0.24%	5.19%
Total Ocotillo	3.46%	0.04%	3.50%	3.41%	0.19%	3.60%
Ocotillo CT Units 1-2						
341.00 Structures and Improvements	5.50%	0.48%	5.98%	6.93%	1.44%	8.37%
342.00 Fuel Holders, Products and Accessories	3.72%	0.19%	3.91%	5.51%	0.28%	5.79%
343.00 Prime Movers	5.41%	0.70%	6.11%	6.23%	0.65%	6.88%
344.00 Generators and Devices	4.73%	0.25%	4.98%	5.88%	0.38%	6.26%
345.00 Accessory Electric Equipment	4.84%	0.27%	5.11%	5.60%	0.30%	5.90%
346.00 Miscellaneous Power Plant Equipment	4.18%	0.20%	4.38%	4.95%	0.24%	5.19%
Total Octillo CT Units 1-2	5.08%	0.48%	5.56%	6.07%	0.57%	6.64%
Ocotillo CT Units 3-7						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	3.33%		3.33%	3.19%	0.16%	3.35%
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total Octillo CT Units 3-7	3.33%		3.33%	3.19%	0.16%	3.35%

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Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro						
341.00 Structures and Improvements	4.20%	0.41%	4.61%	5.14%	1.17%	6.31%
342.00 Fuel Holders, Products and Accessories	2.16%	0.13%	2.29%	3.39%	0.18%	3.57%
343.00 Prime Movers	4.09%	0.48%	4.57%	5.89%	0.58%	6.47%
344.00 Generators and Devices	2.90%	0.15%	3.05%	4.07%	0.21%	4.28%
345.00 Accessory Electric Equipment	4.02%	0.24%	4.26%	4.93%	0.27%	5.20%
346.00 Miscellaneous Power Plant Equipment	2.25%	0.11%	2.36%	3.58%	0.18%	3.76%
Total Saguaro	3.38%	0.27%	3.65%	4.73%	0.38%	5.11%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	4.20%	0.41%	4.61%	5.14%	1.17%	6.31%
342.00 Fuel Holders, Products and Accessories	2.16%	0.13%	2.29%	3.39%	0.18%	3.57%
343.00 Prime Movers	4.10%	0.50%	4.60%	6.08%	0.62%	6.70%
344.00 Generators and Devices	2.72%	0.15%	2.87%	6.40%	0.32%	6.72%
345.00 Accessory Electric Equipment	4.12%	0.25%	4.37%	5.02%	0.28%	5.30%
346.00 Miscellaneous Power Plant Equipment	2.25%	0.11%	2.36%	3.58%	0.18%	3.76%
Total Saguaro CT Units 1-2	3.55%	0.34%	3.89%	5.89%	0.51%	6.40%
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	3.99%	0.20%	4.19%	3.77%	0.19%	3.96%
344.00 Generators and Devices	3.01%	0.15%	3.16%	2.63%	0.14%	2.77%
345.00 Accessory Electric Equipment	3.00%	0.16%	3.16%	3.98%	0.20%	4.18%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	3.08%	0.15%	3.23%	2.73%	0.15%	2.88%
Sundance Units 1-10						
341.00 Structures and Improvements	2.49%	0.23%	2.72%	2.77%	0.23%	3.00%
342.00 Fuel Holders, Products and Accessories	2.45%	0.12%	2.57%	2.63%	0.14%	2.77%
343.00 Prime Movers	2.34%	0.12%	2.46%	2.57%	0.14%	2.71%
344.00 Generators and Devices	4.45%	0.22%	4.67%	4.29%	0.22%	4.51%
345.00 Accessory Electric Equipment	2.41%	0.13%	2.54%	2.65%	0.15%	2.80%
346.00 Miscellaneous Power Plant Equipment	2.85%	0.15%	3.00%	4.42%	0.22%	4.64%
Total Sun Dance Units 1-10	2.46%	0.13%	2.59%	2.71%	0.15%	2.86%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	6.05%	0.46%	6.51%	6.87%	0.45%	7.32%
342.00 Fuel Holders, Products and Accessories	3.36%	0.17%	3.53%	4.78%	0.28%	5.06%
343.00 Prime Movers	5.03%	0.49%	5.52%	5.97%	0.48%	6.45%
344.00 Generators and Devices	4.80%	0.29%	5.09%	6.63%	0.37%	7.00%
345.00 Accessory Electric Equipment	2.61%	0.13%	2.74%	4.97%	0.22%	5.19%
346.00 Miscellaneous Power Plant Equipment	3.52%	0.26%	3.78%	4.87%	0.31%	5.18%
Total West Phoenix CT Units 1-2	4.86%	0.39%	5.25%	6.17%	0.42%	6.59%
Yucca						
341.00 Structures and Improvements	4.72%	0.29%	5.01%	5.37%	1.39%	6.76%
342.00 Fuel Holders, Products and Accessories	1.86%	0.10%	1.96%	2.55%	0.13%	2.68%
343.00 Prime Movers	2.98%	0.20%	3.18%	3.27%	0.22%	3.49%
344.00 Generators and Devices	3.36%	0.21%	3.57%	4.03%	0.27%	4.30%
345.00 Accessory Electric Equipment	2.94%	0.26%	3.20%	3.53%	0.27%	3.80%
346.00 Miscellaneous Power Plant Equipment	2.93%	0.15%	3.08%	3.70%	0.18%	3.88%
Total Yucca	3.06%	0.20%	3.26%	3.45%	0.29%	3.74%

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Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Yucca CT Units 1-4						
341.00 Structures and Improvements	4.99%	0.31%	5.30%	5.75%	1.62%	7.37%
342.00 Fuel Holders, Products and Accessories	1.42%	0.08%	1.50%	2.34%	0.12%	2.46%
343.00 Prime Movers	2.80%	0.44%	3.24%	4.02%	0.47%	4.49%
344.00 Generators and Devices	3.36%	0.21%	3.57%	4.04%	0.27%	4.31%
345.00 Accessory Electric Equipment	2.84%	0.27%	3.11%	3.54%	0.28%	3.82%
346.00 Miscellaneous Power Plant Equipment	2.38%	0.12%	2.50%	3.60%	0.18%	3.78%
Total Yucca CT Units 1-4	3.12%	0.29%	3.41%	4.05%	0.52%	4.57%
Yucca CT Units 5-6						
341.00 Structures and Improvements	3.29%	0.17%	3.46%	3.36%	0.17%	3.53%
342.00 Fuel Holders, Products and Accessories	3.01%	0.15%	3.16%	3.10%	0.16%	3.26%
343.00 Prime Movers	3.01%	0.15%	3.16%	3.13%	0.17%	3.30%
344.00 Generators and Devices	3.14%	0.16%	3.30%	3.45%	0.17%	3.62%
345.00 Accessory Electric Equipment	3.41%	0.23%	3.64%	3.51%	0.22%	3.73%
346.00 Miscellaneous Power Plant Equipment	3.70%	0.19%	3.89%	3.83%	0.20%	4.03%
Total Yucca CT Units 5-6	3.03%	0.15%	3.18%	3.15%	0.17%	3.32%
Solar Units						
341.00 Structures and Improvements	3.54%	0.25%	3.79%	3.48%	0.33%	3.81%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	3.57%	0.25%	3.82%	3.53%	0.33%	3.86%
345.00 Accessory Electric Equipment	3.54%	0.23%	3.77%	3.55%	0.35%	3.90%
346.00 Miscellaneous Power Plant Equipment	3.91%	0.35%	4.26%	3.47%	0.32%	3.79%
Total Solar Units	3.56%	0.25%	3.81%	3.53%	0.32%	3.85%
Chino Valley						
341.05 Structures and Improvements	3.53%	0.26%	3.79%	3.53%	0.27%	3.80%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.53%	0.26%	3.79%	3.53%	0.27%	3.80%
345.05 Accessory Electric Equipment	3.53%	0.26%	3.79%	3.53%	0.27%	3.80%
346.05 Miscellaneous Power Plant Equipment	3.53%	0.26%	3.79%	3.53%	0.27%	3.80%
Total Chino Valley	3.53%	0.26%	3.79%	3.53%	0.27%	3.80%
Cotton Center						
341.05 Structures and Improvements	3.52%	0.24%	3.76%	3.53%	0.24%	3.77%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.52%	0.24%	3.76%	3.55%	0.19%	3.74%
345.05 Accessory Electric Equipment	3.52%	0.24%	3.76%	3.53%	0.24%	3.77%
346.05 Miscellaneous Power Plant Equipment	3.52%	0.24%	3.76%	3.53%	0.24%	3.77%
Total Cotton Center	3.52%	0.24%	3.76%	3.55%	0.20%	3.75%
Desert Star						
341.05 Structures and Improvements	4.51%	0.52%	5.03%	3.43%	0.37%	3.80%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	4.51%	0.52%	5.03%	3.50%	-0.10%	3.40%
345.05 Accessory Electric Equipment	4.51%	0.52%	5.03%	3.43%	0.37%	3.80%
346.05 Miscellaneous Power Plant Equipment	4.51%	0.52%	5.03%	3.43%	0.37%	3.80%
Total Desert Star	4.51%	0.52%	5.03%	3.49%	-0.02%	3.47%

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Component Accrual Rates
Current: VG Procedure / RL Technique
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Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Foothills Units						
341.05 Structures and Improvements	3.48%	0.30%	3.78%	3.49%	0.29%	3.78%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.48%	0.30%	3.78%	3.49%	0.29%	3.78%
345.05 Accessory Electric Equipment	3.48%	0.30%	3.78%	3.49%	0.29%	3.78%
346.05 Miscellaneous Power Plant Equipment	3.48%	0.30%	3.78%	3.49%	0.29%	3.78%
Total Foothills Units	3.48%	0.30%	3.78%	3.49%	0.29%	3.78%
Gila Bend						
341.05 Structures and Improvements	3.46%	0.36%	3.82%	3.45%	0.35%	3.80%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.46%	0.36%	3.82%	3.45%	0.35%	3.80%
345.05 Accessory Electric Equipment	3.46%	0.36%	3.82%	3.45%	0.35%	3.80%
346.05 Miscellaneous Power Plant Equipment	3.46%	0.36%	3.82%	3.45%	0.35%	3.80%
Total Gila Bend	3.46%	0.36%	3.82%	3.45%	0.35%	3.80%
Hyder						
341.05 Structures and Improvements	3.51%	0.16%	3.67%	3.51%	0.15%	3.66%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.50%	0.16%	3.66%	3.50%	0.15%	3.65%
345.05 Accessory Electric Equipment	3.48%	0.16%	3.64%	3.48%	0.15%	3.63%
346.05 Miscellaneous Power Plant Equipment	3.42%	0.15%	3.57%	3.41%	0.15%	3.56%
Total Hyder	3.50%	0.16%	3.66%	3.50%	0.15%	3.65%
Legacy						
341.00 Structures and Improvements	1.31%	0.03%	1.34%	-0.55%	0.02%	-0.53%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	3.44%	0.08%	3.52%	2.48%	0.07%	2.55%
345.00 Accessory Electric Equipment	4.23%	0.22%	4.45%	3.17%	0.14%	3.31%
346.00 Miscellaneous Power Plant Equipment						
Total Legacy	3.51%	0.10%	3.61%	2.51%	0.08%	2.59%
Luke AFB						
341.05 Structures and Improvements	4.51%	0.54%	5.05%	3.42%	0.44%	3.86%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	4.51%	0.54%	5.05%	3.42%	0.44%	3.86%
345.05 Accessory Electric Equipment	4.51%	0.54%	5.05%	3.42%	0.44%	3.86%
346.05 Miscellaneous Power Plant Equipment	4.51%	0.54%	5.05%	3.42%	0.44%	3.86%
Total Luke AFB	4.51%	0.54%	5.05%	3.42%	0.44%	3.86%
Paloma						
341.05 Structures and Improvements	3.52%	0.30%	3.82%	3.53%	0.30%	3.83%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.52%	0.30%	3.82%	3.53%	0.31%	3.84%
345.05 Accessory Electric Equipment	3.52%	0.30%	3.82%	3.53%	0.30%	3.83%
346.05 Miscellaneous Power Plant Equipment	3.52%	0.30%	3.82%	3.53%	0.30%	3.83%
Total Paloma	3.52%	0.30%	3.82%	3.53%	0.31%	3.84%

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Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Red Rock						
341.05 Structures and Improvements	3.33%		3.33%	3.59%	0.56%	4.15%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.59%	0.56%	4.15%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.59%	0.56%	4.15%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.59%	0.56%	4.15%
Total Redrock	3.33%		3.33%	3.59%	0.56%	4.15%
Roof Tops						
341.05 Structures and Improvements	3.53%	0.18%	3.71%	3.70%	0.62%	4.32%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.55%	0.18%	3.73%	3.81%	0.65%	4.46%
345.05 Accessory Electric Equipment	3.54%	0.18%	3.72%	3.88%	0.66%	4.54%
346.05 Miscellaneous Power Plant Equipment						
Total Roof Tops	3.55%	0.18%	3.73%	3.82%	0.65%	4.47%

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION								
311.00 Structures and Improvements	$ 141,937,433	$ 7,116,777	$ 556,174	$ 7,672,951	$ 8,195,586	$ 612,637	$ 8,808,223	$ 1,135,272
312.00 Boiler Plant Equipment	1,491,411,135	43,316,033	4,965,341	48,281,374	65,706,404	6,564,985	72,271,389	23,990,015
314.00 Turbogenerator Units	211,425,539	7,675,326	764,743	8,440,069	10,273,254	985,885	11,259,139	2,819,070
315.00 Accessory Electric Equipment	117,866,116	5,015,509	488,047	5,503,556	5,784,209	476,340	6,260,549	756,993
316.00 Miscellaneous Power Plant Equipment	84,425,866	3,206,651	362,500	3,569,151	3,866,319	341,517	4,207,836	638,685
Total Steam Production Plant	$ 2,047,066,089	$ 66,330,296	$ 7,136,805	$ 73,467,101	$ 93,825,772	$ 8,981,364	$ 102,807,136	$ 29,340,035
NUCLEAR PRODUCTION								
321.00 Structures and Improvements	$ 850,120,585	$ 8,353,862	$ 107,082	$ 8,460,944	$ 9,657,063	$ 128,524	$ 9,785,587	$ 1,324,643
322.00 Reactor Plant Equipment	1,187,263,758	9,081,206	737,370	9,818,576	8,416,265	838,223	9,254,488	(564,088)
323.00 Turbogenerator Units	405,048,258	3,596,722	128,395	3,725,117	4,153,050	18,098	4,171,148	446,031
324.00 Accessory Electric Equipment	294,782,526	1,139,638	17,347	1,156,985	1,236,114	41,849	1,277,963	120,978
325.00 Miscellaneous Power Plant Equipment	233,949,471	3,258,152	119,194	3,377,346	3,885,218	96,089	3,981,307	603,961
Total Nuclear Production Plant	$ 2,971,164,598	$ 25,429,580	$ 1,109,388	$ 26,538,968	$ 27,347,710	$ 1,122,783	$ 28,470,493	$ 1,931,525
OTHER PRODUCTION								
341.00 Structures and Improvements	$ 131,575,027	$ 4,650,609	$ 324,073	$ 4,974,682	$ 5,108,490	$ 479,245	$ 5,587,735	$ 613,053
342.00 Fuel Holders, Products and Accessories	56,786,945	2,047,133	104,977	2,152,110	2,222,257	118,313	2,340,570	188,460
343.00 Prime Movers	655,542,039	21,587,034	1,010,774	22,597,808	23,423,690	1,477,720	24,901,410	2,303,602
344.00 Generators and Devices	2,104,937,839	77,968,261	1,545,723	79,513,984	81,160,482	3,086,425	84,246,907	4,732,923
345.00 Accessory Electric Equipment	247,553,984	9,267,556	572,772	9,840,328	9,750,306	772,062	10,522,368	682,040
346.00 Miscellaneous Power Plant Equipment	34,845,144	1,376,440	71,011	1,447,451	1,608,075	92,951	1,701,026	253,575
Total Other Production Plant	$ 3,231,240,978	$ 116,897,033	$ 3,629,330	$ 120,526,363	$ 123,273,300	$ 6,026,716	$ 129,300,016	$ 8,773,653
TRANSMISSION PLANT								
352.02 Structures and Improvements	$ 151,995	$ 3,815	$ -	$ 3,815	$ 4,043	$ -	$ 4,043	$ 228
353.00 Station Equipment	132,434,328	2,529,496	119,191	2,648,687	2,542,739	119,191	2,661,930	13,243
354.00 Towers and Fixtures	1,329,316	23,662		23,662	23,928		23,928	266
355.00 Poles and Fixtures	1,370,085	25,347	5,069	30,416	25,484	5,069	30,553	137
356.00 Overhead Conductors and Devices	1,947,677	33,890	6,427	40,317	34,279	6,427	40,706	389
Total Transmission Plant	$ 137,233,401	$ 2,616,210	$ 130,687	$ 2,746,897	$ 2,630,473	$ 130,687	$ 2,761,160	$ 14,263
DISTRIBUTION PLANT								
361.00 Structures and Improvements	$ 93,053,192	$ 1,470,240	$ 74,443	$ 1,544,683	$ 1,507,462	$ 148,885	$ 1,656,347	$ 111,664
362.00 Station Equipment	631,870,595	13,901,153	505,496	14,406,649	13,648,405	568,684	14,217,089	(189,560)
363.00 Storage Battery Equipment	13,585,353	1,194,153		1,194,153	1,332,723	33,963	1,366,686	172,533
364.01 Poles, Towers and Fixtures - Wood	357,345,350	7,504,252	678,956	8,183,208	7,718,660	1,536,585	9,255,245	1,072,037
364.02 Poles, Towers and Fixtures - Steel	323,911,866	6,316,281	615,433	6,931,714	6,381,064	615,433	6,996,497	64,783
365.00 Overhead Conductors and Devices	468,658,341	8,998,240	937,317	9,935,557	9,185,703	1,874,633	11,060,336	1,124,779
366.00 Underground Conduit	727,611,816	11,423,506	1,236,940	12,660,446	11,714,550	1,819,030	13,533,580	873,134

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
367.00 Underground Conductors and Devices	1,863,851,442	43,614,124	3,727,703	47,341,827	44,918,820	6,150,710	51,069,530	3,727,703
368.00 Line Transformers	921,018,156	15,657,309	552,611	16,209,920	16,117,818	644,713	16,762,531	552,611
369.00 Services	447,263,911	7,514,034	1,475,971	8,990,005	7,782,392	1,565,424	9,347,816	357,811
370.01 Meters - Electronic	17,843,353	984,953	(5,353)	979,600	1,063,464	(5,353)	1,058,111	78,511
370.03 Meters - AMI	302,666,385	14,649,053		14,649,053	18,825,849		18,825,849	4,176,796
371.00 Installations on Customers' Premises	46,529,246	981,767	144,241	1,126,008	1,000,379	144,241	1,144,620	18,612
373.00 Street Lighting and Signal Systems	80,127,587	1,378,194	144,230	1,522,424	1,418,258	192,306	1,610,564	88,140
Total Distribution Plant	$ 6,295,336,593	$ 135,587,259	$ 10,087,988	$ 145,675,247	$ 142,615,547	$ 15,289,254	$ 157,904,801	$ 12,229,554
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$ 265,654,498	$ 6,694,493	$ 451,613	$ 7,146,106	$ 6,641,362	$ 717,267	$ 7,358,629	$ 212,523
391.CM Office Furn. and Equip. - Computer	243,545,219	31,319,915	48,709	31,368,624	29,590,744	146,127	29,736,871	(1,631,753)
397.00 Communication Equipment	295,372,374	14,266,486		14,266,486	13,941,576	59,074	14,000,650	(265,836)
Total Depreciable	$ 804,572,091	$ 52,280,894	$ 500,322	$ 52,781,216	$ 50,173,682	$ 922,468	$ 51,096,150	$ (1,685,066)
Amortizable								
391.FE Office Furn. and Equip. - Furniture	$ 63,799,361	$ 3,179,056	$ -	$ 3,179,056	$ 3,179,056	$ -	$ 3,179,056	$ -
393.00 Stores Equipment	594,181	29,709		29,709	29,709		29,709	
394.00 Tools, Shop and Garage Equipment	43,094,855	2,147,617		2,147,617	2,147,617		2,147,617	
395.00 Laboratory Equipment	767,547	38,377		38,377	38,377		38,377	
398.00 Miscellaneous Equipment	23,861,303	994,221		994,221	994,221		994,221	
Total Amortizable	$ 132,117,247	$ 6,388,980	$ -	$ 6,388,980	$ 6,388,980	$ -	$ 6,388,980	$ -
Total General Plant	$ 936,689,338	$ 58,669,874	$ 500,322	$ 59,170,196	$ 56,562,662	$ 922,468	$ 57,485,130	$ (1,685,066)
TOTAL UTILITY	$ 15,618,730,997	$ 405,530,252	$ 22,594,520	$ 428,124,772	$ 446,255,464	$ 32,473,272	$ 478,728,736	$ 50,603,964
STEAM PRODUCTION (by Unit)								
Cholla								
311.00 Structures and Improvements	$ 78,078,473	$ 5,504,450	$ 394,240	$ 5,898,690	$ 6,331,634	$ 493,706	$ 6,825,340	$ 926,650
312.00 Boiler Plant Equipment	385,237,434	27,018,838	2,231,038	29,249,876	30,718,192	2,468,167	33,186,359	3,936,483
314.00 Turbogenerator Units	85,554,772	5,671,879	388,323	6,060,202	6,320,784	427,413	6,748,197	687,995
315.00 Accessory Electric Equipment	53,298,558	3,259,945	234,003	3,493,948	3,725,130	267,587	3,992,717	498,769
316.00 Miscellaneous Power Plant Equipment	24,674,267	1,798,701	135,432	1,934,133	2,099,928	156,304	2,256,232	322,099
Total Cholla	$ 626,843,504	$ 43,253,813	$ 3,383,036	$ 46,636,849	$ 49,195,668	$ 3,813,177	$ 53,008,845	$ 6,371,996

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Cholla Unit 1								
311.00 Structures and Improvements	$ 4,743,207	$ 254,236	$ 20,870	$ 275,106	$ 274,632	$ 22,293	$ 296,925	$ 21,819
312.00 Boiler Plant Equipment	82,295,074	4,970,622	534,918	5,505,540	5,489,081	584,295	6,073,376	567,836
314.00 Turbogenerator Units	27,444,492	1,748,214	159,178	1,907,392	1,879,948	170,156	2,050,104	142,712
315.00 Accessory Electric Equipment	9,492,908	520,211	45,566	565,777	561,031	48,414	609,445	43,668
316.00 Miscellaneous Power Plant Equipment	3,742,187	192,723	16,840	209,563	251,849	20,956	272,805	63,242
Total Cholla Unit 1	$ 127,717,868	$ 7,686,006	$ 777,372	$ 8,463,378	$ 8,456,541	$ 846,114	$ 9,302,655	$ 839,277
Cholla Unit 3								
311.00 Structures and Improvements	$ 13,288,725	$ 932,868	$ 61,128	$ 993,996	$ 1,055,125	$ 69,101	$ 1,124,226	$ 130,230
312.00 Boiler Plant Equipment	243,068,426	17,695,381	1,336,876	19,032,257	20,247,600	1,482,717	21,730,317	2,698,060
314.00 Turbogenerator Units	57,062,305	3,834,587	222,543	4,057,130	4,353,854	251,074	4,604,928	547,798
315.00 Accessory Electric Equipment	34,899,789	2,090,497	146,579	2,237,076	2,369,696	167,519	2,537,215	300,139
316.00 Miscellaneous Power Plant Equipment	7,009,816	507,511	36,451	543,962	586,722	43,461	630,183	86,221
Total Cholla Unit 3	$ 355,329,061	$ 25,060,844	$ 1,803,577	$ 26,864,421	$ 28,612,997	$ 2,013,872	$ 30,626,869	$ 3,762,448
Cholla Common								
311.00 Structures and Improvements	$ 60,046,541	$ 4,317,346	$ 312,242	$ 4,629,588	$ 5,001,877	$ 402,312	$ 5,404,189	$ 774,601
312.00 Boiler Plant Equipment	59,873,934	4,352,835	359,244	4,712,079	4,981,511	401,155	5,382,666	670,587
314.00 Turbogenerator Units	1,047,975	89,078	6,602	95,680	86,982	6,183	93,165	(2,515)
315.00 Accessory Electric Equipment	8,905,861	649,237	41,858	691,095	794,403	51,654	846,057	154,962
316.00 Miscellaneous Power Plant Equipment	13,922,264	1,098,467	82,141	1,180,608	1,261,357	91,887	1,353,244	172,636
Total Cholla Common	$ 143,796,575	$ 10,506,963	$ 802,087	$ 11,309,050	$ 12,126,130	$ 953,191	$ 13,079,321	$ 1,770,271
Four Corners								
311.00 Structures and Improvements	$ 63,858,960	$ 1,612,327	$ 161,934	$ 1,774,261	$ 1,863,952	$ 118,931	$ 1,982,883	$ 208,622
312.00 Boiler Plant Equipment	1,106,173,701	16,297,195	2,734,303	19,031,498	34,988,212	4,096,818	39,085,030	20,053,532
314.00 Turbogenerator Units	125,870,767	2,003,447	376,420	2,379,867	3,952,470	558,472	4,510,942	2,131,075
315.00 Accessory Electric Equipment	64,567,558	1,755,564	254,044	2,009,608	2,059,079	208,753	2,267,832	258,224
316.00 Miscellaneous Power Plant Equipment	59,751,599	1,407,950	227,068	1,635,018	1,766,391	185,213	1,951,604	316,586
Total Four Corners	$ 1,420,222,585	$ 23,076,483	$ 3,753,769	$ 26,830,252	$ 44,630,104	$ 5,168,187	$ 49,798,291	$ 22,968,039
Four Corners Units 4-5								
311.00 Structures and Improvements	$ 39,839,762	$ 697,196	$ 123,503	$ 820,699	$ 816,715	$ 75,696	$ 892,411	$ 71,712
312.00 Boiler Plant Equipment	1,066,430,407	14,930,026	2,559,433	17,489,459	33,485,915	3,945,793	37,431,708	19,942,249
314.00 Turbogenerator Units	121,897,287	1,889,408	365,692	2,255,100	3,815,385	548,538	4,363,923	2,108,823
315.00 Accessory Electric Equipment	43,201,151	915,864	177,125	1,092,989	1,123,230	138,244	1,261,474	168,485
316.00 Miscellaneous Power Plant Equipment	39,853,780	805,046	159,415	964,461	996,345	111,591	1,107,936	143,475
Total Four Corners Units 4-5	$ 1,311,222,387	$ 19,237,540	$ 3,385,168	$ 22,622,708	$ 40,237,590	$ 4,819,862	$ 45,057,452	$ 22,434,744

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Four Corners Common								
311.00 Structures and Improvements	$ 24,019,198	$ 915,131	$ 38,431	$ 953,562	$ 1,047,237	$ 43,235	$ 1,090,472	$ 136,910
312.00 Boiler Plant Equipment	39,743,294	1,367,169	174,870	1,542,039	1,502,297	151,025	1,653,322	111,283
314.00 Turbogenerator Units	3,973,480	114,039	10,728	124,767	137,085	9,934	147,019	22,252
315.00 Accessory Electric Equipment	21,366,407	839,700	76,919	916,619	935,849	70,509	1,006,358	89,739
316.00 Miscellaneous Power Plant Equipment	19,897,819	602,904	67,653	670,557	770,046	73,622	843,668	173,111
Total Four Corners Common	$ 109,000,198	$ 3,838,943	$ 368,601	$ 4,207,544	$ 4,392,514	$ 348,325	$ 4,740,839	$ 533,295
NUCLEAR PRODUCTION (by Unit)								
Palo Verde								
321.00 Structures and Improvements	$ 850,120,585	$ 8,353,862	$ 107,082	$ 8,460,944	$ 9,657,063	$ 128,524	$ 9,785,587	$ 1,324,643
322.00 Reactor Plant Equipment	1,187,263,758	9,081,206	737,370	9,818,576	8,416,265	838,223	9,254,488	(564,088)
323.00 Turbogenerator Units	405,048,258	3,596,722	128,395	3,725,117	4,153,050	18,098	4,171,148	446,031
324.00 Accessory Electric Equipment	294,782,526	1,139,638	17,347	1,156,985	1,236,114	41,849	1,277,963	120,978
325.00 Miscellaneous Power Plant Equipment	233,949,471	3,258,152	119,194	3,377,346	3,885,218	96,089	3,981,307	603,961
Total Palo Verde	$ 2,971,164,598	$ 25,429,580	$ 1,109,388	$ 26,538,968	$ 27,347,710	$ 1,122,783	$ 28,470,493	$ 1,931,525
Palo Verde Unit 1								
321.00 Structures and Improvements	$ 169,287,979	$ 304,718	$ -	$ 304,718	$ 507,864	$ 16,929	$ 524,793	$ 220,075
322.00 Reactor Plant Equipment	465,986,593	2,795,920	46,599	2,842,519	2,609,525	93,197	2,702,722	(139,797)
323.00 Turbogenerator Units	144,321,116	1,140,137	72,161	1,212,298	1,414,347	115,457	1,529,804	317,506
324.00 Accessory Electric Equipment	121,319,415	230,507		230,507	279,035	12,132	291,167	60,660
325.00 Miscellaneous Power Plant Equipment	33,599,919	134,400	13,440	147,840	188,160	10,080	198,240	50,400
Total Palo Verde Unit 1	$ 934,515,022	$ 4,605,682	$ 132,200	$ 4,737,882	$ 4,998,931	$ 247,795	$ 5,246,726	$ 508,844
Palo Verde Unit 2								
321.00 Structures and Improvements	$ 94,477,904	$ 349,568	$ -	$ 349,568	$ 311,777	$ 9,448	$ 321,225	$ (28,343)
322.00 Reactor Plant Equipment	248,880,636	2,389,254	149,328	2,538,582	2,190,150	149,328	2,339,478	(199,104)
323.00 Turbogenerator Units	87,819,612	974,798	26,346	1,001,144	966,016	43,910	1,009,926	8,782
324.00 Accessory Electric Equipment	49,752,711	233,838	4,975	238,813	223,887	4,975	228,862	(9,951)
325.00 Miscellaneous Power Plant Equipment	27,865,592	192,273	8,360	200,633	167,194	8,360	175,554	(25,079)
Total Palo Verde Unit 2	$ 508,796,455	$ 4,139,731	$ 189,009	$ 4,328,740	$ 3,859,024	$ 216,021	$ 4,075,045	$ (253,695)
Palo Verde Unit 3								
321.00 Structures and Improvements	$167,896,725.00	$ 486,901	$ -	$ 486,901	$ 369,373	$ -	$ 369,373	$ (117,528)
322.00 Reactor Plant Equipment	436,634,437	3,536,739	392,971	3,929,710	3,143,768	436,634	3,580,402	(349,308)
323.00 Turbogenerator Units	167,364,071	1,355,649	16,736	1,372,385	1,640,168	(150,628)	1,489,540	117,155
324.00 Accessory Electric Equipment	95,765,260	373,485	9,577	383,062	344,755	19,153	363,908	(19,154)
325.00 Miscellaneous Power Plant Equipment	29,878,581	164,332	11,951	176,283	149,393	11,951	161,344	(14,939)
Total Palo Verde Unit 3	$ 897,539,074	$ 5,917,106	$ 431,235	$ 6,348,341	$ 5,647,457	$ 317,110	$ 5,964,567	$ (383,774)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual Investment	Net Salvage	Total	Proposed 2019 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Palo Verde Water Reclamation								
321.00 Structures and Improvements	$ 233,902,104	$ 4,794,993	$ 70,171	$ 4,865,164	$ 5,496,699	$ 46,780	$ 5,543,479	$ 678,315
322.00 Reactor Plant Equipment	454,911	13,283	182	13,465	13,829	182	14,011	546
323.00 Turbogenerator Units	217,756	3,114	370	3,484	3,637	305	3,942	458
324.00 Accessory Electric Equipment								
325.00 Miscellaneous Power Plant Equipment	241,107	5,280	24	5,304	6,438	8,752	15,190	9,886
Total Palo Verde Water Reclamation	$ 234,815,878	$ 4,816,670	$ 70,747	$ 4,887,417	$ 5,520,603	$ 56,019	$ 5,576,622	$ 689,205
Palo Verde Common								
321.00 Structures and Improvements	$ 184,555,873	$ 2,417,682	$ 36,911	$ 2,454,593	$ 2,971,350	$ 55,367	$ 3,026,717	$ 572,124
322.00 Reactor Plant Equipment	35,307,181	346,010	148,290	494,300	458,993	158,882	617,875	123,575
323.00 Turbogenerator Units	5,325,703	123,024	12,782	135,806	128,882	9,054	137,936	2,130
324.00 Accessory Electric Equipment	27,945,140	301,808	2,795	304,603	388,437	5,589	394,026	89,423
325.00 Miscellaneous Power Plant Equipment	142,364,272	2,761,867	85,419	2,847,286	3,374,033	56,946	3,430,979	583,693
Total Palo Verde Common	$ 395,498,169	$ 5,950,391	$ 286,197	$ 6,236,588	$ 7,321,695	$ 285,838	$ 7,607,533	$ 1,370,945
OTHER PRODUCTION								
Combined Cycle								
341.00 Structures and Improvements	$ 63,600,586	$ 2,107,372	$ 131,304	$ 2,238,676	$ 2,404,625	$ 133,087	$ 2,537,712	$ 299,036
342.00 Fuel Holders, Products and Accessories	41,829,313	1,652,145	84,706	1,736,851	1,729,348	92,103	1,821,451	84,600
343.00 Prime Movers	274,702,584	10,121,342	539,819	10,661,161	10,476,390	579,920	11,056,310	395,149
344.00 Generators and Devices	727,795,468	29,917,431	(368,782)	29,548,649	33,354,267	(330,003)	33,024,264	3,475,615
345.00 Accessory Electric Equipment	78,442,697	3,449,660	201,290	3,650,950	3,811,854	252,855	4,064,709	413,759
346.00 Miscellaneous Power Plant Equipment	20,741,997	934,600	45,066	979,666	1,015,182	60,380	1,075,562	95,896
Total Combined Cycle	$ 1,207,112,645	$ 48,182,550	$ 633,403	$ 48,815,953	$ 52,791,666	$ 788,342	$ 53,580,008	$ 4,764,055
Redhawk CC Units 1-2								
341.00 Structures and Improvements	$ 23,988,173	$ 959,527	$ 47,976	$ 1,007,503	$ 983,515	$ 47,976	$ 1,031,491	$ 23,988
342.00 Fuel Holders, Products and Accessories	12,809,613	559,780	29,462	589,242	594,366	34,586	628,952	39,710
343.00 Prime Movers	132,414,998	5,256,875	344,279	5,601,154	5,415,773	370,762	5,786,535	185,381
344.00 Generators and Devices	391,212,295	16,939,492	(430,334)	16,509,158	18,347,857	(704,182)	17,643,675	1,134,517
345.00 Accessory Electric Equipment	29,897,838	1,186,944	56,806	1,243,750	1,291,587	98,663	1,390,250	146,500
346.00 Miscellaneous Power Plant Equipment	6,872,469	303,076	13,745	316,821	316,821	13,745	330,566	13,745
Total Redhawk CC Units 1-2	$ 597,195,386	$ 25,205,694	$ 61,934	$ 25,267,628	$ 26,949,919	$ (138,450)	$ 26,811,469	$ 1,543,841

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual Investment	Net Salvage	Total	Proposed 2019 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix								
341.00 Structures and Improvements	$ 39,612,413	$ 1,147,845	$ 83,328	$ 1,231,173	$ 1,421,110	$ 85,111	$ 1,506,221	$ 275,048
342.00 Fuel Holders, Products and Accessories	29,019,700	1,092,365	55,244	1,147,609	1,134,982	57,517	1,192,499	44,890
343.00 Prime Movers	142,287,586	4,864,467	195,540	5,060,007	5,060,617	209,158	5,269,775	209,768
344.00 Generators and Devices	336,583,173	12,977,939	61,552	13,039,491	15,006,410	374,179	15,380,589	2,341,098
345.00 Accessory Electric Equipment	48,544,859	2,262,716	144,484	2,407,200	2,520,267	154,192	2,674,459	267,259
346.00 Miscellaneous Power Plant Equipment	13,869,528	631,524	31,321	662,845	698,361	46,635	744,996	82,151
Total West Phoenix	$ 609,917,259	$ 22,976,856	$ 571,469	$ 23,548,325	$ 25,841,747	$ 926,792	$ 26,768,539	$ 3,220,214
West Phoenix CC Units 1-3								
341.00 Structures and Improvements	$ 366,217	$ 14,759	$ 696	$ 15,455	$ 15,418	$ 769	$ 16,187	$ 732
342.00 Fuel Holders, Products and Accessories	22,031,967	868,059	44,064	912,123	826,199	41,861	868,060	(44,063)
343.00 Prime Movers								
344.00 Generators and Devices	130,345,213	5,213,809	182,483	5,396,292	6,478,157	312,829	6,790,986	1,394,694
345.00 Accessory Electric Equipment	32,620,455	1,699,526	114,172	1,813,698	1,895,248	120,696	2,015,944	202,246
346.00 Miscellaneous Power Plant Equipment	8,073,969	389,165	18,570	407,735	440,839	33,103	473,942	66,207
Total West Phoenix CC Units 1-3	$ 193,437,821	$ 8,185,318	$ 359,985	$ 8,545,303	$ 9,655,861	$ 509,258	$ 10,165,119	$ 1,619,816
West Phoenix CC Unit 4								
341.00 Structures and Improvements	$ 7,035,987	$ 232,188	$ 11,961	$ 244,149	$ 289,883	$ 14,776	$ 304,659	$ 60,510
342.00 Fuel Holders, Products and Accessories	4,470,010	143,487	7,152	150,639	148,404	7,599	156,003	5,364
343.00 Prime Movers	49,464,010	1,587,795	9,893	1,597,688	1,607,580	4,946	1,612,526	14,838
344.00 Generators and Devices	23,956,815	910,359	43,122	953,481	927,129	43,122	970,251	16,770
345.00 Accessory Electric Equipment	552,377	22,095	1,105	23,200	23,973	1,215	25,188	1,988
346.00 Miscellaneous Power Plant Equipment	942,600	42,417	2,074	44,491	44,962	1,885	46,847	2,356
Total West Phoenix CC Unit 4	$ 86,421,799	$ 2,938,341	$ 75,307	$ 3,013,648	$ 3,041,931	$ 73,543	$ 3,115,474	$ 101,826
West Phoenix CC Unit 5								
341.00 Structures and Improvements	$ 11,054,705	$ 384,704	$ 19,898	$ 404,602	$ 413,446	$ 18,793	$ 432,239	$ 27,637
342.00 Fuel Holders, Products and Accessories	2,517,723	80,819	4,028	84,847	160,379	8,057	168,436	83,589
343.00 Prime Movers	92,823,576	3,276,672	185,647	3,462,319	3,453,037	204,212	3,657,249	194,930
344.00 Generators and Devices	182,281,145	6,853,771	(164,053)	6,689,718	7,601,124	18,228	7,619,352	929,634
345.00 Accessory Electric Equipment	15,372,027	541,095	29,207	570,302	601,046	32,281	633,327	63,025
346.00 Miscellaneous Power Plant Equipment	4,852,959	199,942	10,677	210,619	212,560	11,647	224,207	13,588
Total West Phoenix CC Unit 5	$ 308,902,135	$ 11,337,003	$ 85,404	$ 11,422,407	$ 12,441,592	$ 293,218	$ 12,734,810	$ 1,312,403

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual Investment	Net Salvage	Total	Proposed 2019 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix Common								
341.00 Structures and Improvements	$ 21,155,504	$ 516,194	$ 50,773	$ 566,967	$ 702,363	$ 50,773	$ 753,136	$ 186,169
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices								
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total West Phoenix Common	$ 21,155,504	$ 516,194	$ 50,773	$ 566,967	$ 702,363	$ 50,773	$ 753,136	$ 186,169
Combustion Turbine								
341.00 Structures and Improvements	$ 31,102,449	$ 1,238,442	$ 99,263	$ 1,337,705	$ 1,422,644	$ 226,766	$ 1,649,410	$ 311,705
342.00 Fuel Holders, Products and Accessories	14,957,632	394,988	20,271	415,259	492,909	26,210	519,119	103,860
343.00 Prime Movers	380,839,455	11,465,692	470,955	11,936,647	12,947,300	897,800	13,845,100	1,908,453
344.00 Generators and Devices	689,863,781	23,548,896	199,699	23,748,595	23,573,757	1,210,251	24,784,008	1,035,413
345.00 Accessory Electric Equipment	42,078,140	1,319,888	75,988	1,395,876	1,428,524	81,802	1,510,326	114,450
346.00 Miscellaneous Power Plant Equipment	12,525,501	380,177	20,381	400,558	538,150	27,550	565,700	165,142
Total Combustion Turbine	$ 1,171,366,958	$ 38,348,083	$ 886,557	$ 39,234,640	$ 40,403,284	$ 2,470,379	$ 42,873,663	$ 3,639,023
Douglas CT								
341.00 Structures and Improvements	$ 103,952	$ 16,767	$ 842	$ 17,609	$ 9,418	$ 478	$ 9,896	$ (7,713)
342.00 Fuel Holders, Products and Accessories	137,759	33,186	1,488	34,674	12,660	634	13,294	(21,380)
343.00 Prime Movers	3,721,569	423,142	(341,268)	81,874	334,569	11,165	345,734	263,860
344.00 Generators and Devices	971,924	184,374	9,233	193,607	88,542	4,374	92,916	(100,691)
345.00 Accessory Electric Equipment	582,402	137,097	6,348	143,445	52,882	2,621	55,503	(87,942)
346.00 Miscellaneous Power Plant Equipment	33,564	8,082	430	8,512	3,085	154	3,239	(5,273)
Total Douglas CT	$ 5,551,170	$ 802,648	$ (322,927)	$ 479,721	$ 501,156	$ 19,426	$ 520,582	$ 40,861
Ocotillo								
341.00 Structures and Improvements	$ 3,189,602	$ 175,428	$ 15,310	$ 190,738	$ 221,039	$ 45,930	$ 266,969	$ 76,231
342.00 Fuel Holders, Products and Accessories	1,484,432	55,221	2,820	58,041	81,792	4,156	85,948	27,907
343.00 Prime Movers	24,161,626	1,307,144	169,131	1,476,275	1,505,269	157,051	1,662,320	186,045
344.00 Generators and Devices	612,033,648	20,597,536	38,717	20,636,253	19,940,469	1,013,325	20,953,794	317,541
345.00 Accessory Electric Equipment	4,017,658	194,455	10,848	205,303	224,989	12,053	237,042	31,739
346.00 Miscellaneous Power Plant Equipment	950,460	39,729	1,901	41,630	47,048	2,281	49,329	7,699
Total Ocotillo	$ 645,837,426	$ 22,369,513	$ 238,727	$ 22,608,240	$ 22,020,606	$ 1,234,796	$ 23,255,402	$ 647,162

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Ocotillo CT Units 1-2								
341.00 Structures and Improvements	$ 3,189,602	$ 175,428	$ 15,310	$ 190,738	$ 221,039	$ 45,930	$ 266,969	$ 76,231
342.00 Fuel Holders, Products and Accessories	1,484,432	55,221	2,820	58,041	81,792	4,156	85,948	27,907
343.00 Prime Movers	24,161,626	1,307,144	169,131	1,476,275	1,505,269	157,051	1,662,320	186,045
344.00 Generators and Devices	15,486,821	732,527	38,717	771,244	910,625	58,850	969,475	198,231
345.00 Accessory Electric Equipment	4,017,658	194,455	10,848	205,303	224,989	12,053	237,042	31,739
346.00 Miscellaneous Power Plant Equipment	950,460	39,729	1,901	41,630	47,048	2,281	49,329	7,699
Total Ocotillo CT Units 1-2	$ 49,290,599	$ 2,504,504	$ 238,727	$ 2,743,231	$ 2,990,762	$ 280,321	$ 3,271,083	$ 527,852
Ocotillo CT Units 3-7								
341.00 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	596,546,827	19,865,009		19,865,009	19,029,844	954,475	19,984,319	119,310
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total Ocotillo CT Units 3-7	$ 596,546,827	$ 19,865,009	$ -	$ 19,865,009	$ 19,029,844	$ 954,475	$ 19,984,319	$ 119,310
Saguaro								
341.00 Structures and Improvements	$ 3,051,365	$ 128,157	$ 12,511	$ 140,668	$ 156,840	$ 35,701	$ 192,541	$ 51,873
342.00 Fuel Holders, Products and Accessories	1,642,488	35,478	2,135	37,613	55,680	2,956	58,636	21,023
343.00 Prime Movers	23,292,483	952,858	110,645	1,063,503	1,371,385	136,075	1,507,460	443,957
344.00 Generators and Devices	38,498,152	1,116,094	57,748	1,173,842	1,567,613	80,401	1,648,014	474,172
345.00 Accessory Electric Equipment	3,593,189	144,412	8,691	153,103	177,010	9,802	186,812	33,709
346.00 Miscellaneous Power Plant Equipment	916,172	20,614	1,008	21,622	32,799	1,649	34,448	12,826
Total Saguaro	$ 70,993,849	$ 2,397,613	$ 192,738	$ 2,590,351	$ 3,361,327	$ 266,584	$ 3,627,911	$ 1,037,560
Saguaro CT Units 1-2								
341.00 Structures and Improvements	$ 3,051,365	$ 128,157	$ 12,511	$ 140,668	$ 156,840	$ 35,701	$ 192,541	$ 51,873
342.00 Fuel Holders, Products and Accessories	1,642,488	35,478	2,135	37,613	55,680	2,956	58,636	21,023
343.00 Prime Movers	21,353,178	875,480	106,766	982,246	1,298,273	132,390	1,430,663	448,417
344.00 Generators and Devices	14,724,431	400,505	22,087	422,592	942,364	47,118	989,482	566,890
345.00 Accessory Electric Equipment	3,269,324	134,696	8,173	142,869	164,120	9,154	173,274	30,405
346.00 Miscellaneous Power Plant Equipment	916,172	20,614	1,008	21,622	32,799	1,649	34,448	12,826
Total Saguaro CT Units 1-2	$ 44,956,958	$ 1,594,930	$ 152,680	$ 1,747,610	$ 2,650,076	$ 228,968	$ 2,879,044	$ 1,131,434

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Saguaro CT Unit 3								
341.00 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	1,939,305	77,378	3,879	81,257	73,112	3,685	76,797	(4,460)
344.00 Generators and Devices	23,773,721	715,589	35,661	751,250	625,249	33,283	658,532	(92,718)
345.00 Accessory Electric Equipment	323,865	9,716	518	10,234	12,890	648	13,538	3,304
346.00 Miscellaneous Power Plant Equipment								
Total Saguaro CT Unit 3	$ 26,036,891	$ 802,683	$ 40,058	$ 842,741	$ 711,251	$ 37,616	$ 748,867	$ (93,874)
Sundance Units 1-10								
341.00 Structures and Improvements	$ 13,762,067	$ 342,675	$ 31,653	$ 374,328	$ 381,209	$ 31,653	$ 412,862	$ 38,534
342.00 Fuel Holders, Products and Accessories	4,418,231	108,247	5,302	113,549	116,199	6,186	122,385	8,836
343.00 Prime Movers	227,932,672	5,333,625	273,519	5,607,144	5,857,870	319,106	6,176,976	569,832
344.00 Generators and Devices	13,058,506	581,104	28,729	609,833	560,210	28,729	588,939	(20,894)
345.00 Accessory Electric Equipment	27,804,255	670,083	36,146	706,229	736,813	41,706	778,519	72,290
346.00 Miscellaneous Power Plant Equipment	6,970,933	198,672	10,456	209,128	308,115	15,336	323,451	114,323
Total Sun Dance Units 1-10	$ 293,946,664	$ 7,234,406	$ 385,805	$ 7,620,211	$ 7,960,416	$ 442,716	$ 8,403,132	$ 782,921
West Phoenix CT Units 1-2								
341.00 Structures and Improvements	$ 4,239,486	$ 256,489	$ 19,502	$ 275,991	$ 291,253	$ 19,078	$ 310,331	$ 34,340
342.00 Fuel Holders, Products and Accessories	1,843,219	61,932	3,133	65,065	88,106	5,161	93,267	28,202
343.00 Prime Movers	20,466,623	1,029,471	100,286	1,129,757	1,221,857	98,240	1,320,097	190,340
344.00 Generators and Devices	15,280,205	733,450	44,313	777,763	1,013,078	56,537	1,069,615	291,852
345.00 Accessory Electric Equipment	1,525,954	39,827	1,984	41,811	75,840	3,357	79,197	37,386
346.00 Miscellaneous Power Plant Equipment	1,026,473	36,132	2,669	38,801	49,989	3,182	53,171	14,370
Total West Phoenix CT Units 1-2	$ 44,381,960	$ 2,157,301	$ 171,887	$ 2,329,188	$ 2,740,123	$ 185,555	$ 2,925,678	$ 596,490
Yucca								
341.00 Structures and Improvements	$ 6,755,977	$ 318,926	$ 19,445	$ 338,371	$ 362,885	$ 93,926	$ 456,811	$ 118,440
342.00 Fuel Holders, Products and Accessories	5,431,503	100,924	5,393	106,317	138,472	7,117	145,589	39,272
343.00 Prime Movers	81,264,482	2,419,452	158,642	2,578,094	2,656,350	176,163	2,832,513	254,419
344.00 Generators and Devices	10,021,346	336,338	20,959	357,297	403,845	26,885	430,730	73,433
345.00 Accessory Electric Equipment	4,554,682	134,014	11,971	145,985	160,990	12,263	173,253	27,268
346.00 Miscellaneous Power Plant Equipment	2,627,899	76,948	3,917	80,865	97,114	4,948	102,062	21,197
Total Yucca	$ 110,655,889	$ 3,386,602	$ 220,327	$ 3,606,929	$ 3,819,656	$ 321,302	$ 4,140,958	$ 534,029

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Yucca CT Units 1-4								
341.00 Structures and Improvements	$ 5,685,548	$ 283,709	$ 17,625	$ 301,334	$ 326,919	$ 92,106	$ 419,025	$ 117,691
342.00 Fuel Holders, Products and Accessories	3,934,860	55,875	3,148	59,023	92,076	4,722	96,798	37,775
343.00 Prime Movers	12,670,962	354,787	55,752	410,539	509,373	59,554	568,927	158,388
344.00 Generators and Devices	9,848,867	330,922	20,683	351,605	397,894	26,592	424,486	72,881
345.00 Accessory Electric Equipment	3,737,069	106,133	10,090	116,223	132,292	10,464	142,756	26,533
346.00 Miscellaneous Power Plant Equipment	1,536,718	36,574	1,844	38,418	55,322	2,766	58,088	19,670
Total Yucca CT Units 1-4	$ 37,414,024	$ 1,168,000	$ 109,142	$ 1,277,142	$ 1,513,876	$ 196,204	$ 1,710,080	$ 432,938
Yucca CT Units 5-6								
341.00 Structures and Improvements	$ 1,070,429	$ 35,217	$ 1,820	$ 37,037	$ 35,966	$ 1,820	$ 37,786	$ 749
342.00 Fuel Holders, Products and Accessories	1,496,643	45,049	2,245	47,294	46,396	2,395	48,791	1,497
343.00 Prime Movers	68,593,520	2,064,665	102,890	2,167,555	2,146,977	116,609	2,263,586	96,031
344.00 Generators and Devices	172,479	5,416	276	5,692	5,951	293	6,244	552
345.00 Accessory Electric Equipment	817,613	27,881	1,881	29,762	28,698	1,799	30,497	735
346.00 Miscellaneous Power Plant Equipment	1,091,181	40,374	2,073	42,447	41,792	2,182	43,974	1,527
Total Yucca CT Units 5-6	$ 73,241,865	$ 2,218,602	$ 111,185	$ 2,329,787	$ 2,305,780	$ 125,098	$ 2,430,878	$ 101,091
Solar Units								
341.00 Structures and Improvements	$ 36,871,992	$ 1,304,795	$ 93,506	$ 1,398,301	$ 1,281,221	$ 119,392	$ 1,400,613	$ 2,312
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	687,278,590	24,501,934	1,714,806	26,216,740	24,232,458	2,206,177	26,438,635	221,895
345.00 Accessory Electric Equipment	127,033,147	4,498,008	295,494	4,793,502	4,509,928	437,405	4,947,333	153,831
346.00 Miscellaneous Power Plant Equipment	1,577,646	61,663	5,564	67,227	54,743	5,021	59,764	(7,463)
Total Solar Units	$ 852,761,375	$ 30,366,400	$ 2,109,370	$ 32,475,770	$ 30,078,350	$ 2,767,995	$ 32,846,345	$ 370,575
Chino Valley								
341.05 Structures and Improvements	$ 527,890	$ 18,635	$ 1,373	$ 20,008	$ 18,635	$ 1,425	$ 20,060	$ 52
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	77,719,184	2,743,487	202,070	2,945,557	2,743,487	209,842	2,953,329	7,772
345.05 Accessory Electric Equipment	6,511,784	229,866	16,931	246,797	229,866	17,582	247,448	651
346.05 Miscellaneous Power Plant Equipment	216,504	7,643	563	8,206	7,643	585	8,228	22
Total Chino Valley	$ 84,975,362	$ 2,999,631	$ 220,937	$ 3,220,568	$ 2,999,631	$ 229,434	$ 3,229,065	$ 8,497

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Cotton Center								
341.05 Structures and Improvements	$ 1,813,499	$ 63,835	$ 4,352	$ 68,187	$ 64,017	$ 4,352	$ 68,369	$ 182
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	62,644,922	2,205,101	150,348	2,355,449	2,223,895	119,025	2,342,920	(12,529)
345.05 Accessory Electric Equipment	15,418,007	542,714	37,003	579,717	544,256	37,003	581,259	1,542
346.05 Miscellaneous Power Plant Equipment	262,640	9,245	630	9,875	9,271	630	9,901	26
Total Cotton Center	$ 80,139,068	$ 2,820,895	$ 192,333	$ 3,013,228	$ 2,841,439	$ 161,010	$ 3,002,449	$ (10,779)
Desert Star								
341.05 Structures and Improvements	$ 1,557,800	$ 70,257	$ 8,101	$ 78,358	$ 53,433	$ 5,764	$ 59,197	$ (19,161)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	29,042,805	1,309,831	151,023	1,460,854	1,016,498	(29,043)	987,455	(473,399)
345.05 Accessory Electric Equipment	4,084,919	184,230	21,242	205,472	140,113	15,114	155,227	(50,245)
346.05 Miscellaneous Power Plant Equipment	291,809	13,161	1,517	14,678	10,009	1,080	11,089	(3,589)
Total Desert Star	$ 34,977,333	$ 1,577,479	$ 181,883	$ 1,759,362	$ 1,220,053	$ (7,085)	$ 1,212,968	$ (546,394)
Foothills Units								
341.05 Structures and Improvements	$ 10,906,684	$ 379,553	$ 32,720	$ 412,273	$ 380,643	$ 31,629	$ 412,272	$ (1)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	105,443,248	3,669,425	316,330	3,985,755	3,679,969	305,785	3,985,754	(1)
345.05 Accessory Electric Equipment	20,815,540	724,381	62,447	786,828	726,462	60,365	786,827	(1)
346.05 Miscellaneous Power Plant Equipment	57,708	2,008	173	2,181	2,014	167	2,181	
Total Foothills Units	$ 137,223,180	$ 4,775,367	$ 411,670	$ 5,187,037	$ 4,789,088	$ 397,946	$ 5,187,034	$ (3)
Gila Bend								
341.05 Structures and Improvements	$ 5,018,097	$ 173,626	$ 18,065	$ 191,691	$ 173,124	$ 17,563	$ 190,687	$ (1,004)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	89,246,612	3,087,933	321,288	3,409,221	3,079,008	312,363	3,391,371	(17,850)
345.05 Accessory Electric Equipment	11,096,944	383,954	39,949	423,903	382,845	38,839	421,684	(2,219)
346.05 Miscellaneous Power Plant Equipment	21,142	732	76	808	729	74	803	(5)
Total Gila Bend	$ 105,382,795	$ 3,646,245	$ 379,378	$ 4,025,623	$ 3,635,706	$ 368,839	$ 4,004,545	$ (21,078)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Hyder								
341.05 Structures and Improvements	$ 6,915,232	$ 242,725	$ 11,064	$ 253,789	$ 242,725	$ 10,373	$ 253,098	$ (691)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	93,250,197	3,263,757	149,200	3,412,957	3,263,757	139,875	3,403,632	(9,325)
345.05 Accessory Electric Equipment	22,556,482	784,966	36,090	821,056	784,966	33,835	818,801	(2,255)
346.05 Miscellaneous Power Plant Equipment	206,389	7,059	310	7,369	7,038	310	7,348	(21)
Total Hyder	$ 122,928,300	$ 4,298,507	$ 196,664	$ 4,495,171	$ 4,298,486	$ 184,393	$ 4,482,879	$ (12,292)
Legacy								
341.00 Structures and Improvements	$ 313,214	$ 4,103	$ 94	$ 4,197	$ (1,723)	$ 63	$ (1,660)	$ (5,857)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	10,452,105	359,552	8,362	367,914	259,212	7,316	266,528	(101,386)
345.00 Accessory Electric Equipment	1,972,486	83,436	4,339	87,775	62,528	2,761	65,289	(22,486)
346.00 Miscellaneous Power Plant Equipment								
Total Legacy	$ 12,737,805	$ 447,091	$ 12,795	$ 459,886	$ 320,017	$ 10,140	$ 330,157	$ (129,729)
Luke AFB								
341.05 Structures and Improvements	$ 1,488,329	$ 67,124	$ 8,037	$ 75,161	$ 50,901	$ 6,549	$ 57,450	$ (17,711)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	25,469,888	1,148,692	137,537	1,286,229	871,070	112,068	983,138	(303,091)
345.05 Accessory Electric Equipment	1,757,020	79,242	9,488	88,730	60,090	7,731	67,821	(20,909)
346.05 Miscellaneous Power Plant Equipment	357,678	16,131	1,931	18,062	12,233	1,574	13,807	(4,255)
Total Luke AFB	$ 29,072,915	$ 1,311,189	$ 156,993	$ 1,468,182	$ 994,294	$ 127,922	$ 1,122,216	$ (345,966)
Paloma								
341.05 Structures and Improvements	$ 2,281,950	$ 80,325	$ 6,846	$ 87,171	$ 80,553	$ 6,846	$ 87,399	$ 228
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	49,207,939	1,732,119	147,624	1,879,743	1,737,040	152,545	1,889,585	9,842
345.05 Accessory Electric Equipment	12,514,947	440,526	37,545	478,071	441,778	37,545	479,323	1,252
346.05 Miscellaneous Power Plant Equipment	121,486	4,276	364	4,640	4,288	364	4,652	12
Total Paloma	$ 64,126,322	$ 2,257,246	$ 192,379	$ 2,449,625	$ 2,263,659	$ 197,300	$ 2,460,959	$ 11,334

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual Investment	Net Salvage	Total	Proposed 2019 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Red Rock								
341.05 Structures and Improvements	$ 4,463,879	$ 148,647	$ -	$ 148,647	$ 160,253	$ 24,998	$ 185,251	$ 36,604
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	72,010,410	2,397,947		2,397,947	2,585,174	403,258	2,988,432	590,485
345.05 Accessory Electric Equipment	13,383,040	445,655		445,655	480,451	74,945	555,396	109,741
346.05 Miscellaneous Power Plant Equipment	42,290	1,408		1,408	1,518	237	1,755	347
Total Redrock	$ 89,899,619	$ 2,993,657	$ -	$ 2,993,657	$ 3,227,396	$ 503,438	$ 3,730,834	$ 737,177
Roof Tops								
341.05 Structures and Improvements	$ 1,585,418	$ 55,965	$ 2,854	$ 58,819	$ 58,660	$ 9,830	$ 68,490	$ 9,671
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	72,791,280	2,584,090	131,024	2,715,114	2,773,348	473,143	3,246,491	531,377
345.05 Accessory Electric Equipment	16,921,978	599,038	30,460	629,498	656,573	111,685	768,258	138,760
346.05 Miscellaneous Power Plant Equipment								
Total Roof Tops	$ 91,298,676	$ 3,239,093	$ 164,338	$ 3,403,431	$ 3,488,581	$ 594,658	$ 4,083,239	$ 679,808

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$ 141,937,433	$ 70,349,340	49.56%	$ 82,547,199	58.16%	$ 72,283,777	50.93%
312.00 Boiler Plant Equipment	1,491,411,135	709,065,790	47.54%	629,291,816	42.19%	692,936,249	46.46%
314.00 Turbogenerator Units	211,425,539	94,840,375	44.86%	103,864,897	49.13%	103,083,344	48.76%
315.00 Accessory Electric Equipment	117,866,116	56,775,610	48.17%	64,893,268	55.06%	59,619,255	50.58%
316.00 Miscellaneous Power Plant Equipment	84,425,866	37,830,698	44.81%	40,045,625	47.43%	40,939,187	48.49%
Total Steam Production Plant	$ 2,047,066,089	$ 968,861,812	47.33%	$ 920,642,805	44.97%	$ 968,861,812	47.33%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$ 850,120,585	$ 432,691,790	50.90%	$ 348,117,564	40.95%	$ 430,094,870	50.59%
322.00 Reactor Plant Equipment	1,187,263,758	677,764,052	57.09%	517,753,190	43.61%	670,979,119	56.51%
323.00 Turbogenerator Units	405,048,258	198,640,744	49.04%	160,235,841	39.56%	207,867,040	51.32%
324.00 Accessory Electric Equipment	294,782,526	185,001,401	62.76%	142,385,715	48.30%	184,098,954	62.45%
325.00 Miscellaneous Power Plant Equipment	233,949,471	88,709,442	37.92%	70,807,951	30.27%	89,767,444	38.37%
Total Nuclear Production Plant	$ 2,971,164,598	$ 1,582,807,428	53.27%	$ 1,239,300,261	41.71%	$ 1,582,807,428	53.27%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 131,575,027	$ 35,451,261	26.94%	$ 39,407,583	29.95%	$ 37,666,409	28.63%
342.00 Fuel Holders, Products and Accessories	56,786,945	26,898,551	47.37%	28,373,750	49.97%	26,541,703	46.74%
343.00 Prime Movers	655,542,039	269,866,990	41.17%	264,211,048	40.30%	259,658,256	39.61%
344.00 Generators and Devices	2,104,937,839	369,238,514	17.54%	454,023,321	21.57%	374,181,849	17.78%
345.00 Accessory Electric Equipment	247,553,984	63,395,509	25.61%	70,583,118	28.51%	66,746,440	26.96%
346.00 Miscellaneous Power Plant Equipment	34,845,144	9,634,963	27.65%	10,718,913	30.76%	9,691,130	27.81%
Total Other Production Plant	$ 3,231,240,978	$ 774,485,788	23.97%	$ 867,317,732	26.84%	$ 774,485,788	23.97%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$ 151,995	$ 113,034	74.37%	$ 122,246	80.43%	$ 110,605	72.77%
353.00 Station Equipment	132,434,328	30,719,777	23.20%	34,049,834	25.71%	30,807,429	23.26%
354.00 Towers and Fixtures	1,329,316	623,782	46.93%	663,124	49.88%	599,978	45.13%
355.00 Poles and Fixtures	1,370,085	393,906	28.75%	404,811	29.55%	366,263	26.73%
356.00 Overhead Conductors and Devices	1,947,677	734,906	37.73%	774,923	39.79%	701,131	36.00%
Total Transmission Plant	$ 137,233,401	$ 32,585,406	23.74%	$ 36,014,938	26.24%	$ 32,585,406	23.74%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$ 93,053,192	$ 24,784,504	26.63%	$ 21,495,505	23.10%	$ 24,117,620	25.92%
362.00 Station Equipment	631,870,595	152,459,460	24.13%	119,308,223	18.88%	133,861,958	21.19%
363.00 Storage Battery Equipment	13,585,353	(242,468)	-1.78%	1,533,841	11.29%	1,720,945	12.67%
364.01 Poles, Towers and Fixtures - Wood	357,345,350	94,269,551	26.38%	96,616,197	27.04%	108,401,860	30.34%
364.02 Poles, Towers and Fixtures - Steel	323,911,866	54,022,644	16.68%	40,630,852	12.54%	45,587,180	14.07%
365.00 Overhead Conductors and Devices	468,658,341	85,935,082	18.34%	76,845,701	16.40%	86,219,673	18.40%
366.00 Underground Conduit	727,611,816	208,762,604	28.69%	181,124,928	24.89%	203,219,332	27.93%
367.00 Underground Conductors and Devices	1,863,851,442	640,622,806	34.37%	539,076,287	28.92%	604,835,151	32.45%
368.00 Line Transformers	921,018,156	274,977,840	29.86%	227,089,449	24.66%	254,790,805	27.66%
369.00 Services	447,263,911	141,008,738	31.53%	123,303,844	27.57%	138,344,982	30.93%
370.01 Meters - Electronic	17,843,353	4,356,437	24.41%	2,463,630	13.81%	2,764,154	15.49%
370.03 Meters - AMI	302,666,385	47,048,548	15.54%	112,520,045	37.18%	126,245,728	41.71%
371.00 Installations on Customers' Premises	46,529,246	13,161,123	28.29%	10,824,012	23.26%	12,144,372	26.10%
373.00 Street Lighting and Signal Systems	80,127,587	25,060,492	31.28%	21,367,146	26.67%	23,973,603	29.92%
Total Distribution Plant	$ 6,295,336,593	$ 1,766,227,362	28.06%	$ 1,574,199,660	25.01%	$ 1,766,227,362	28.06%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 265,654,498	$ 33,232,710	12.51%	$ 42,706,660	16.08%	$ 43,160,983	16.25%
391.CM Office Furn. and Equip. - Computer	243,545,219	113,384,516	46.56%	109,465,517	44.95%	110,630,038	45.42%
397.00 Communication Equipment	295,372,374	108,507,607	36.74%	102,227,593	34.61%	103,315,115	34.98%
Total Depreciable	$ 804,572,091	$ 255,124,832	31.71%	$ 254,399,770	31.62%	$ 257,106,137	31.96%
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$ 63,799,361	$ 34,632,270	54.28%	$ 34,177,862	53.57%	$ 34,177,862	53.57%
393.00 Stores Equipment	594,181	159,335	26.82%	162,894	27.41%	162,894	27.41%
394.00 Tools, Shop and Garage Equipment	43,094,855	21,913,348	50.85%	20,743,001	48.13%	20,743,001	48.13%
395.00 Laboratory Equipment	767,547	489,181	63.73%	492,765	64.20%	492,765	64.20%
398.00 Miscellaneous Equipment	23,861,303	6,665,059	27.93%	6,301,368	26.41%	6,301,368	26.41%
Total Amortizable	$ 132,117,247	$ 63,859,194	48.34%	$ 61,877,890	46.84%	$ 61,877,890	46.84%
Total General Plant	$ 936,689,338	$ 318,984,027	34.05%	$ 316,277,660	33.77%	$ 318,984,027	34.05%
TOTAL UTILITY	$ 15,618,730,997	$ 5,443,951,822	34.86%	$ 4,953,753,056	31.72%	$ 5,443,951,822	34.86%

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$ 78,078,473	$ 38,575,882	49.41%	$ 56,662,385	72.57%	$ 39,706,361	50.85%
312.00 Boiler Plant Equipment	385,237,434	203,229,153	52.75%	269,673,742	70.00%	199,913,198	51.89%
314.00 Turbogenerator Units	85,554,772	47,896,982	55.98%	63,935,487	74.73%	48,476,834	56.66%
315.00 Accessory Electric Equipment	53,298,558	30,464,401	57.16%	42,757,564	80.22%	31,459,855	59.03%
316.00 Miscellaneous Power Plant Equipment	24,674,267	11,356,450	46.03%	16,594,143	67.25%	11,966,620	48.50%
Total Cholla	$ 626,843,504	$ 331,522,868	52.89%	$ 449,623,321	71.73%	$ 331,522,868	52.89%
Cholla Unit 1							
311.00 Structures and Improvements	$ 4,743,207	$ 3,184,960	67.15%	$ 3,748,682	79.03%	$ 3,219,192	67.87%
312.00 Boiler Plant Equipment	82,295,074	50,638,747	61.53%	58,295,076	70.84%	50,061,075	60.83%
314.00 Turbogenerator Units	27,444,492	16,306,099	59.41%	19,255,663	70.16%	16,535,860	60.25%
315.00 Accessory Electric Equipment	9,492,908	6,262,264	65.97%	7,394,449	77.89%	6,350,006	66.89%
316.00 Miscellaneous Power Plant Equipment	3,742,187	2,070,672	55.33%	2,674,353	71.46%	2,296,609	61.37%
Total Cholla Unit 1	$ 127,717,868	$ 78,462,742	61.43%	$ 91,368,223	71.54%	$ 78,462,742	61.43%
Cholla Unit 3							
311.00 Structures and Improvements	$ 13,288,725	$ 6,623,928	49.85%	$ 9,725,808	73.19%	$ 6,958,137	52.36%
312.00 Boiler Plant Equipment	243,068,426	121,796,129	50.11%	168,012,254	69.12%	120,201,033	49.45%
314.00 Turbogenerator Units	57,062,305	31,015,320	54.35%	43,912,565	76.96%	31,416,373	55.06%
315.00 Accessory Electric Equipment	34,899,789	20,381,771	58.40%	29,369,052	84.15%	21,011,505	60.21%
316.00 Miscellaneous Power Plant Equipment	7,009,816	3,213,795	45.85%	4,813,741	68.67%	3,443,895	49.13%
Total Cholla Unit 3	$ 355,329,061	$ 183,030,943	51.51%	$ 255,833,421	72.00%	$ 183,030,943	51.51%
Cholla Common							
311.00 Structures and Improvements	$ 60,046,541	$ 28,766,995	47.91%	$ 43,187,895	71.92%	$ 29,529,032	49.18%
312.00 Boiler Plant Equipment	59,873,934	30,794,277	51.43%	43,366,412	72.43%	29,651,091	49.52%
314.00 Turbogenerator Units	1,047,975	575,563	54.92%	767,258	73.21%	524,600	50.06%
315.00 Accessory Electric Equipment	8,905,861	3,820,365	42.90%	5,994,063	67.30%	4,098,345	46.02%
316.00 Miscellaneous Power Plant Equipment	13,922,264	6,071,983	43.61%	9,106,049	65.41%	6,226,116	44.72%
Total Cholla Common	$ 143,796,575	$ 70,029,184	48.70%	$ 102,421,677	71.23%	$ 70,029,184	48.70%

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Four Corners							
311.00 Structures and Improvements	$ 63,858,960	$ 31,773,458	49.76%	$ 25,884,814	40.53%	$ 32,577,416	51.01%
312.00 Boiler Plant Equipment	1,106,173,701	505,836,637	45.73%	359,618,074	32.51%	493,023,051	44.57%
314.00 Turbogenerator Units	125,870,767	46,943,393	37.29%	39,929,410	31.72%	54,606,511	43.38%
315.00 Accessory Electric Equipment	64,567,558	26,311,209	40.75%	22,135,704	34.28%	28,159,399	43.61%
316.00 Miscellaneous Power Plant Equipment	59,751,599	26,474,248	44.31%	23,451,482	39.25%	28,972,568	48.49%
Total Four Corners	$ 1,420,222,585	$ 637,338,944	44.88%	$ 471,019,484	33.17%	$ 637,338,944	44.88%
Four Corners Units 4-5							
311.00 Structures and Improvements	$ 39,839,762	$ 26,512,392	66.55%	$ 19,611,711	49.23%	$ 27,315,993	68.56%
312.00 Boiler Plant Equipment	1,066,430,407	493,094,646	46.24%	345,419,361	32.39%	481,114,204	45.11%
314.00 Turbogenerator Units	121,897,287	45,574,050	37.39%	38,108,838	31.26%	53,079,548	43.54%
315.00 Accessory Electric Equipment	43,201,151	22,772,976	52.71%	17,313,382	40.08%	24,114,787	55.82%
316.00 Miscellaneous Power Plant Equipment	39,853,780	21,055,267	52.83%	16,789,283	42.13%	23,384,800	58.68%
Total Four Corners Units 4-5	$ 1,311,222,387	$ 609,009,331	46.45%	$ 437,242,577	33.35%	$ 609,009,331	46.45%
Four Corners Common							
311.00 Structures and Improvements	$ 24,019,198	$ 5,261,065	21.90%	$ 6,273,103	26.12%	$ 5,261,422	21.91%
312.00 Boiler Plant Equipment	39,743,294	12,741,991	32.06%	14,198,712	35.73%	11,908,847	29.96%
314.00 Turbogenerator Units	3,973,480	1,369,343	34.46%	1,820,572	45.82%	1,526,963	38.43%
315.00 Accessory Electric Equipment	21,366,407	3,538,233	16.56%	4,822,322	22.57%	4,044,613	18.93%
316.00 Miscellaneous Power Plant Equipment	19,897,819	5,418,980	27.23%	6,662,199	33.48%	5,587,768	28.08%
Total Four Corners Common	$ 109,000,198	$ 28,329,613	25.99%	$ 33,776,907	30.99%	$ 28,329,613	25.99%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$ 850,120,585	$ 432,691,790	50.90%	$ 348,117,564	40.95%	$ 430,094,870	50.59%
322.00 Reactor Plant Equipment	1,187,263,758	677,764,052	57.09%	517,753,190	43.61%	670,979,119	56.51%
323.00 Turbogenerator Units	405,048,258	198,640,744	49.04%	160,235,841	39.56%	207,867,040	51.32%
324.00 Accessory Electric Equipment	294,782,526	185,001,401	62.76%	142,385,715	48.30%	184,098,954	62.45%
325.00 Miscellaneous Power Plant Equipment	233,949,471	88,709,442	37.92%	70,807,951	30.27%	89,767,444	38.37%
Total Palo Verde	$ 2,971,164,598	$ 1,582,807,428	53.27%	$ 1,239,300,261	41.71%	$ 1,582,807,428	53.27%

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Palo Verde Unit 1							
321.00 Structures and Improvements	$ 169,287,979	$ 113,114,947	66.82%	$ 86,088,078	50.85%	$ 111,921,549	66.11%
322.00 Reactor Plant Equipment	465,986,593	287,237,408	61.64%	221,653,492	47.57%	288,167,686	61.84%
323.00 Turbogenerator Units	144,321,116	74,895,472	51.90%	58,781,248	40.73%	76,420,435	52.95%
324.00 Accessory Electric Equipment	121,319,415	82,787,025	68.24%	62,939,373	51.88%	81,826,338	67.45%
325.00 Miscellaneous Power Plant Equipment	33,599,919	20,834,661	62.01%	15,794,009	47.01%	20,533,505	61.11%
Total Palo Verde Unit 1	$ 934,515,022	$ 578,869,513	61.94%	$ 445,256,200	47.65%	$ 578,869,513	61.94%
Palo Verde Unit 2							
321.00 Structures and Improvements	$ 94,477,904	$ 62,447,235	66.10%	$ 48,795,819	51.65%	$ 62,198,364	65.83%
322.00 Reactor Plant Equipment	248,880,636	139,105,347	55.89%	107,732,446	43.29%	137,322,870	55.18%
323.00 Turbogenerator Units	87,819,612	42,490,094	48.38%	34,978,907	39.83%	44,586,419	50.77%
324.00 Accessory Electric Equipment	49,752,711	31,501,138	63.32%	24,738,254	49.72%	31,533,007	63.38%
325.00 Miscellaneous Power Plant Equipment	27,865,592	16,921,154	60.72%	13,198,994	47.37%	16,824,307	60.38%
Total Palo Verde Unit 2	$ 508,796,455	$ 292,464,968	57.48%	$ 229,444,421	45.10%	$ 292,464,968	57.48%
Palo Verde Unit 3							
321.00 Structures and Improvements	$ 167,896,725	$ 107,517,902	64.04%	$ 81,684,945	48.65%	$ 106,853,469	63.64%
322.00 Reactor Plant Equipment	436,634,437	236,799,254	54.23%	177,162,392	40.57%	231,749,145	53.08%
323.00 Turbogenerator Units	167,364,071	80,085,013	47.85%	65,470,961	39.12%	85,643,680	51.17%
324.00 Accessory Electric Equipment	95,765,260	57,980,208	60.54%	44,510,437	46.48%	58,224,861	60.80%
325.00 Miscellaneous Power Plant Equipment	29,878,581	17,348,950	58.06%	13,194,669	44.16%	17,260,172	57.77%
Total Palo Verde Unit 3	$ 897,539,074	$ 499,731,327	55.68%	$ 382,023,405	42.56%	$ 499,731,327	55.68%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$ 233,902,104	$ 74,873,790	32.01%	$ 70,914,080	30.32%	$ 74,709,524	31.94%
322.00 Reactor Plant Equipment	454,911	(315,403)	-69.33%	65,600	14.42%	69,111	15.19%
323.00 Turbogenerator Units	217,756	104,964	48.20%	95,049	43.65%	100,136	45.99%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	241,107	56,987	23.64%	(150,382)	-62.37%	(158,431)	-65.71%
Total Palo Verde Water Reclamation	$ 234,815,878	$ 74,720,339	31.82%	$ 70,924,346	30.20%	$ 74,720,339	31.82%

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Palo Verde Common							
321.00 Structures and Improvements	$ 184,555,873	$ 74,737,915	40.50%	$ 60,634,641	32.85%	$ 74,411,964	40.32%
322.00 Reactor Plant Equipment	35,307,181	14,937,445	42.31%	11,139,260	31.55%	13,670,308	38.72%
323.00 Turbogenerator Units	5,325,703	1,065,201	20.00%	909,676	17.08%	1,116,371	20.96%
324.00 Accessory Electric Equipment	27,945,140	12,733,029	45.56%	10,197,652	36.49%	12,514,748	44.78%
325.00 Miscellaneous Power Plant Equipment	142,364,272	33,547,691	23.56%	28,770,660	20.21%	35,307,891	24.80%
Total Palo Verde Common	$ 395,498,169	$ 137,021,281	34.65%	$ 111,651,888	28.23%	$ 137,021,281	34.65%
OTHER PRODUCTION							
Combined Cycle							
341.00 Structures and Improvements	$ 63,600,586	$ 18,701,434	29.40%	$ 22,799,732	35.85%	$ 20,220,947	31.79%
342.00 Fuel Holders, Products and Accessories	41,829,313	18,054,578	43.16%	19,714,363	47.13%	18,146,036	43.38%
343.00 Prime Movers	274,702,584	95,474,865	34.76%	116,291,024	42.33%	86,697,343	31.56%
344.00 Generators and Devices	727,795,468	201,653,014	27.71%	270,971,681	37.23%	206,753,284	28.41%
345.00 Accessory Electric Equipment	78,442,697	20,068,505	25.58%	26,640,732	33.96%	21,966,673	28.00%
346.00 Miscellaneous Power Plant Equipment	20,741,997	5,209,055	25.11%	6,326,926	30.50%	5,377,167	25.92%
Total Combined Cycle	$ 1,207,112,645	$ 359,161,451	29.75%	$ 462,744,458	38.33%	$ 359,161,451	29.75%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$ 23,988,173	$ 6,434,553	26.82%	$ 9,977,489	41.59%	$ 6,551,241	27.31%
342.00 Fuel Holders, Products and Accessories	12,809,613	1,858,155	14.51%	3,176,511	24.80%	2,085,704	16.28%
343.00 Prime Movers	132,414,998	36,154,393	27.30%	52,507,606	39.65%	34,476,612	26.04%
344.00 Generators and Devices	391,212,295	90,340,613	23.09%	139,906,675	35.76%	91,863,036	23.48%
345.00 Accessory Electric Equipment	29,897,838	6,334,454	21.19%	9,596,019	32.10%	6,300,767	21.07%
346.00 Miscellaneous Power Plant Equipment	6,872,469	1,400,145	20.37%	1,896,053	27.59%	1,244,952	18.12%
Total Redhawk CC Units 1-2	$ 597,195,386	$ 142,522,314	23.87%	$ 217,060,352	36.35%	$ 142,522,314	23.87%
West Phoenix							
341.00 Structures and Improvements	$ 39,612,413	$ 12,266,881	30.97%	$ 12,822,243	32.37%	$ 13,669,706	34.51%
342.00 Fuel Holders, Products and Accessories	29,019,700	16,196,423	55.81%	16,537,852	56.99%	16,060,331	55.34%
343.00 Prime Movers	142,287,586	59,320,471	41.69%	63,783,419	44.83%	52,220,732	36.70%
344.00 Generators and Devices	336,583,173	111,312,401	33.07%	131,065,007	38.94%	114,890,248	34.13%
345.00 Accessory Electric Equipment	48,544,859	13,734,051	28.29%	17,044,713	35.11%	15,665,906	32.27%
346.00 Miscellaneous Power Plant Equipment	13,869,528	3,808,910	27.46%	4,430,874	31.95%	4,132,215	29.79%
Total West Phoenix	$ 609,917,259	$ 216,639,138	35.52%	$ 245,684,106	40.28%	$ 216,639,138	35.52%

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West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$ 366,217	$ (174,165)	-47.56%	$ 201,780	55.10%	$ 201,293	54.97%
342.00 Fuel Holders, Products and Accessories	22,031,967	14,160,758	64.27%	13,331,306	60.51%	13,299,135	60.36%
343.00 Prime Movers							
344.00 Generators and Devices	130,345,213	61,299,140	47.03%	60,018,475	46.05%	59,873,641	45.93%
345.00 Accessory Electric Equipment	32,620,455	9,777,883	29.97%	11,449,742	35.10%	11,422,112	35.02%
346.00 Miscellaneous Power Plant Equipment	8,073,969	2,842,783	35.21%	3,117,741	38.61%	3,110,218	38.52%
Total West Phoenix CC Units 1-3	$ 193,437,821	$ 87,906,399	45.44%	$ 88,119,044	45.55%	$ 87,906,399	45.44%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$ 7,035,987	$ 2,018,949	28.69%	$ 2,398,614	34.09%	$ 2,177,748	30.95%
342.00 Fuel Holders, Products and Accessories	4,470,010	2,035,665	45.54%	2,231,577	49.92%	2,026,092	45.33%
343.00 Prime Movers	49,464,010	24,639,897	49.81%	26,824,918	54.23%	24,354,859	49.24%
344.00 Generators and Devices	23,956,815	8,472,007	35.36%	9,413,492	39.29%	8,546,690	35.68%
345.00 Accessory Electric Equipment	552,377	143,454	25.97%	164,429	29.77%	149,289	27.03%
346.00 Miscellaneous Power Plant Equipment	942,600	132,993	14.11%	207,385	22.00%	188,289	19.98%
Total West Phoenix CC Unit 4	$ 86,421,799	$ 37,442,966	43.33%	$ 41,240,415	47.72%	$ 37,442,966	43.33%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$ 11,054,705	$ 2,517,789	22.78%	$ 4,491,324	40.63%	$ 3,386,356	30.63%
342.00 Fuel Holders, Products and Accessories	2,517,723			974,969	38.72%	735,105	29.20%
343.00 Prime Movers	92,823,576	34,680,574	37.36%	36,958,501	39.82%	27,865,873	30.02%
344.00 Generators and Devices	182,281,145	41,541,253	22.79%	61,633,040	33.81%	46,469,917	25.49%
345.00 Accessory Electric Equipment	15,372,027	3,812,715	24.80%	5,430,542	35.33%	4,094,505	26.64%
346.00 Miscellaneous Power Plant Equipment	4,852,959	833,134	17.17%	1,105,748	22.79%	833,709	17.18%
Total West Phoenix CC Unit 5	$ 308,902,135	$ 83,385,465	26.99%	$ 110,594,123	35.80%	$ 83,385,465	26.99%
West Phoenix Common							
341.00 Structures and Improvements	$ 21,155,504	$ 7,904,308	37.36%	$ 5,730,525	27.09%	$ 7,904,308	37.36%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices							
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total West Phoenix Common	$ 21,155,504	$ 7,904,308	37.36%	$ 5,730,525	27.09%	$ 7,904,308	37.36%

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Combustion Turbine							
341.00 Structures and Improvements	$ 31,102,449	$ 10,228,622	32.89%	$ 9,625,235	30.95%	$ 10,723,333	34.48%
342.00 Fuel Holders, Products and Accessories	14,957,632	8,843,973	59.13%	8,659,387	57.89%	8,395,667	56.13%
343.00 Prime Movers	380,839,455	174,392,126	45.79%	147,920,024	38.84%	172,960,913	45.42%
344.00 Generators and Devices	689,863,781	37,302,414	5.41%	46,325,853	6.72%	38,103,473	5.52%
345.00 Accessory Electric Equipment	42,078,140	20,677,181	49.14%	18,830,310	44.75%	21,378,077	50.81%
346.00 Miscellaneous Power Plant Equipment	12,525,501	4,137,658	33.03%	4,090,899	32.66%	4,020,511	32.10%
Total Combustion Turbine	$ 1,171,366,958	$ 255,581,974	21.82%	$ 235,451,707	20.10%	$ 255,581,974	21.82%
Douglas CT							
341.00 Structures and Improvements	$ 103,952	$ (109,082)	-104.94%	$ 53,167	51.15%	$ (2,933)	-2.82%
342.00 Fuel Holders, Products and Accessories	137,759	(301,173)	-218.62%	105,207	76.37%	(5,803)	-4.21%
343.00 Prime Movers	3,721,569	2,728,550	73.32%	204,962	5.51%	(11,306)	-0.30%
344.00 Generators and Devices	971,924	(1,480,347)	-152.31%	586,003	60.29%	(32,325)	-3.33%
345.00 Accessory Electric Equipment	582,402	(834,397)	-143.27%	313,807	53.88%	(17,310)	-2.97%
346.00 Miscellaneous Power Plant Equipment	33,564	(74,654)	-222.42%	25,845	77.00%	(1,426)	-4.25%
Total Douglas CT	$ 5,551,170	$ (71,102)	-1.28%	$ 1,288,991	23.22%	$ (71,102)	-1.28%
Ocotillo							
341.00 Structures and Improvements	$ 3,189,602	$ 65,746	2.06%	$ 426,443	13.37%	$ 325,151	10.19%
342.00 Fuel Holders, Products and Accessories	1,484,432	581,896	39.20%	767,366	51.69%	585,095	39.42%
343.00 Prime Movers	24,161,626	6,082,793	25.18%	8,558,860	35.42%	6,525,889	27.01%
344.00 Generators and Devices	612,033,648	8,902,408	1.45%	16,020,014	2.62%	8,242,082	1.35%
345.00 Accessory Electric Equipment	4,017,658	1,504,914	37.46%	2,007,447	49.97%	1,530,622	38.10%
346.00 Miscellaneous Power Plant Equipment	950,460	510,095	53.67%	575,775	60.58%	439,012	46.19%
Total Ocotillo	$ 645,837,426	$ 17,647,852	2.73%	$ 28,355,906	4.39%	$ 17,647,852	2.73%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$ 3,189,602	$ 65,746	2.06%	$ 426,443	13.37%	$ 325,151	10.19%
342.00 Fuel Holders, Products and Accessories	1,484,432	581,896	39.20%	767,366	51.69%	585,095	39.42%
343.00 Prime Movers	24,161,626	6,082,793	25.18%	8,558,860	35.42%	6,525,889	27.01%
344.00 Generators and Devices	15,486,821	5,931,627	38.30%	6,913,437	44.64%	5,271,301	34.04%
345.00 Accessory Electric Equipment	4,017,658	1,504,914	37.46%	2,007,447	49.97%	1,530,622	38.10%
346.00 Miscellaneous Power Plant Equipment	950,460	510,095	53.67%	575,775	60.58%	439,012	46.19%
Total Octillo CT Units 1-2	$ 49,290,599	$ 14,677,070	29.78%	$ 19,249,328	39.05%	$ 14,677,070	29.78%

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Ocotillo CT Units 3-7							
341.00 Structures and Improvements	$ -	$ -		$ -		$ -	
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	596,546,827	2,970,782	0.50%	9,106,578	1.53%	2,970,782	0.50%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total Octillo CT Units 3-7	$ 596,546,827	$ 2,970,782	0.50%	$ 9,106,578	1.53%	$ 2,970,782	0.50%
Saguaro							
341.00 Structures and Improvements	$ 3,051,365	$ 1,442,471	47.27%	$ 1,119,690	36.69%	$ 1,021,922	33.49%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,271,253	77.40%	1,161,496	70.72%	1,060,077	64.54%
343.00 Prime Movers	23,292,483	5,718,981	24.55%	7,393,588	31.74%	6,872,727	29.51%
344.00 Generators and Devices	38,498,152	17,877,019	46.44%	16,242,291	42.19%	17,335,026	45.03%
345.00 Accessory Electric Equipment	3,593,189	1,454,205	40.47%	1,694,376	47.16%	1,564,699	43.55%
346.00 Miscellaneous Power Plant Equipment	916,172	662,539	72.32%	626,742	68.41%	572,017	62.44%
Total Saguaro	$ 70,993,849	$ 28,426,468	40.04%	$ 28,238,184	39.78%	$ 28,426,468	40.04%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$ 3,051,365	$ 1,442,471	47.27%	$ 1,119,690	36.69%	$ 1,021,922	33.49%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,271,253	77.40%	1,161,496	70.72%	1,060,077	64.54%
343.00 Prime Movers	21,353,178	5,183,748	24.28%	6,817,804	31.93%	6,222,492	29.14%
344.00 Generators and Devices	14,724,431	4,647,555	31.56%	4,650,787	31.59%	4,244,693	28.83%
345.00 Accessory Electric Equipment	3,269,324	1,383,086	42.30%	1,610,034	49.25%	1,469,450	44.95%
346.00 Miscellaneous Power Plant Equipment	916,172	662,539	72.32%	626,742	68.41%	572,017	62.44%
Total Saguaro CT Units 1-2	$ 44,956,958	$ 14,590,652	32.45%	$ 15,986,553	35.56%	$ 14,590,652	32.45%
Saguaro CT Unit 3							
341.00 Structures and Improvements	$ -	$ -		$ -		$ -	
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	1,939,305	535,233	27.60%	575,784	29.69%	650,235	33.53%
344.00 Generators and Devices	23,773,721	13,229,464	55.65%	11,591,504	48.76%	13,090,333	55.06%
345.00 Accessory Electric Equipment	323,865	71,120	21.96%	84,342	26.04%	95,248	29.41%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$ 26,036,891	$ 13,835,816	53.14%	$ 12,251,630	47.05%	$ 13,835,816	53.14%

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Sundance Units 1-10							
341.00 Structures and Improvements	$ 13,762,067	$ 6,860,041	49.85%	$ 5,221,536	37.94%	$ 6,999,321	50.86%
342.00 Fuel Holders, Products and Accessories	4,418,231	2,391,416	54.13%	1,811,844	41.01%	2,428,725	54.97%
343.00 Prime Movers	227,932,672	129,018,866	56.60%	95,403,699	41.86%	127,885,963	56.11%
344.00 Generators and Devices	13,058,506	1,972,219	15.10%	2,293,663	17.56%	3,074,591	23.54%
345.00 Accessory Electric Equipment	27,804,255	15,482,562	55.68%	11,306,832	40.67%	15,156,488	54.51%
346.00 Miscellaneous Power Plant Equipment	6,970,933	1,296,100	18.59%	1,101,191	15.80%	1,476,116	21.18%
Total Sun Dance Units 1-10	$ 293,946,664	$ 157,021,204	53.42%	$ 117,138,765	39.85%	$ 157,021,204	53.42%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$ 4,239,486	$ 1,109,653	26.17%	$ 1,292,297	30.48%	$ 933,566	22.02%
342.00 Fuel Holders, Products and Accessories	1,843,219	1,100,840	59.72%	1,217,230	66.04%	879,337	47.71%
343.00 Prime Movers	20,466,623	5,881,051	28.73%	9,054,952	44.24%	6,541,374	31.96%
344.00 Generators and Devices	15,280,205	4,269,530	27.94%	5,424,296	35.50%	3,918,557	25.64%
345.00 Accessory Electric Equipment	1,525,954	463,354	30.36%	975,425	63.92%	704,655	46.18%
346.00 Miscellaneous Power Plant Equipment	1,026,473	628,767	61.26%	658,497	64.15%	475,703	46.34%
Total West Phoenix CT Units 1-2	$ 44,381,960	$ 13,453,194	30.31%	$ 18,622,696	41.96%	$ 13,453,194	30.31%
Yucca							
341.00 Structures and Improvements	$ 6,755,977	$ 859,793	12.73%	$ 1,512,102	22.38%	$ 1,446,305	21.41%
342.00 Fuel Holders, Products and Accessories	5,431,503	3,799,741	69.96%	3,596,244	66.21%	3,448,236	63.49%
343.00 Prime Movers	81,264,482	24,961,885	30.72%	27,303,963	33.60%	25,146,265	30.94%
344.00 Generators and Devices	10,021,346	5,761,585	57.49%	5,759,585	57.47%	5,565,541	55.54%
345.00 Accessory Electric Equipment	4,554,682	2,606,543	57.23%	2,532,423	55.60%	2,438,923	53.55%
346.00 Miscellaneous Power Plant Equipment	2,627,899	1,114,812	42.42%	1,102,849	41.97%	1,059,088	40.30%
Total Yucca	$ 110,655,889	$ 39,104,358	35.34%	$ 41,807,165	37.78%	$ 39,104,358	35.34%
Yucca CT Units 1-4							
341.00 Structures and Improvements	$ 5,685,548	$ 616,237	10.84%	$ 1,262,131	22.20%	$ 1,220,102	21.46%
342.00 Fuel Holders, Products and Accessories	3,934,860	3,357,198	85.32%	3,138,934	79.77%	3,034,408	77.12%
343.00 Prime Movers	12,670,962	6,731,737	53.13%	7,096,573	56.01%	6,860,259	54.14%
344.00 Generators and Devices	9,848,867	5,727,556	58.15%	5,723,145	58.11%	5,532,566	56.17%
345.00 Accessory Electric Equipment	3,737,069	2,473,783	66.20%	2,383,991	63.79%	2,304,605	61.67%
346.00 Miscellaneous Power Plant Equipment	1,536,718	1,001,468	65.17%	988,970	64.36%	956,038	62.21%
Total Yucca CT Units 1-4	$ 37,414,024	$ 19,907,978	53.21%	$ 20,593,744	55.04%	$ 19,907,978	53.21%

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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Yucca CT Units 5-6							
341.00 Structures and Improvements	$ 1,070,429	$ 243,556	22.75%	$ 249,971	23.35%	$ 226,203	21.13%
342.00 Fuel Holders, Products and Accessories	1,496,643	442,543	29.57%	457,310	30.56%	413,828	27.65%
343.00 Prime Movers	68,593,520	18,230,148	26.58%	20,207,390	29.46%	18,286,006	26.66%
344.00 Generators and Devices	172,479	34,030	19.73%	36,440	21.13%	32,975	19.12%
345.00 Accessory Electric Equipment	817,613	132,760	16.24%	148,432	18.15%	134,318	16.43%
346.00 Miscellaneous Power Plant Equipment	1,091,181	113,344	10.39%	113,879	10.44%	103,051	9.44%
Total Yucca CT Units 5-6	$ 73,241,865	$ 19,196,381	26.21%	$ 21,213,422	28.96%	$ 19,196,381	26.21%
Solar Units							
341.00 Structures and Improvements	$ 36,871,992	$ 6,521,205	17.69%	$ 6,982,617	18.94%	$ 6,722,129	18.23%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	687,278,590	130,283,085	18.96%	136,725,787	19.89%	129,325,092	18.82%
345.00 Accessory Electric Equipment	127,033,147	22,649,823	17.83%	25,112,076	19.77%	23,401,690	18.42%
346.00 Miscellaneous Power Plant Equipment	1,577,646	288,249	18.27%	301,087	19.08%	293,452	18.60%
Total Solar Units	$ 852,761,375	$ 159,742,363	18.73%	$ 169,121,567	19.83%	$ 159,742,363	18.73%
Chino Valley							
341.05 Structures and Improvements	$ 527,890	$ 110,183	20.87%	$ 120,132	22.76%	$ 110,182	20.87%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	77,719,184	16,221,704	20.87%	17,686,608	22.76%	16,221,704	20.87%
345.05 Accessory Electric Equipment	6,511,784	1,359,153	20.87%	1,481,891	22.76%	1,359,153	20.87%
346.05 Miscellaneous Power Plant Equipment	216,504	45,189	20.87%	49,270	22.76%	45,189	20.87%
Total Chino Valley	$ 84,975,362	$ 17,736,228	20.87%	$ 19,337,902	22.76%	$ 17,736,228	20.87%
Cotton Center							
341.05 Structures and Improvements	$ 1,813,499	$ 442,322	24.39%	$ 474,336	26.16%	$ 441,884	24.37%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	62,644,922	15,731,380	25.11%	16,891,250	26.96%	15,735,612	25.12%
345.05 Accessory Electric Equipment	15,418,007	3,760,538	24.39%	4,032,712	26.16%	3,756,808	24.37%
346.05 Miscellaneous Power Plant Equipment	262,640	64,060	24.39%	68,696	26.16%	63,996	24.37%
Total Cotton Center	$ 80,139,068	$ 19,998,300	24.95%	$ 21,466,993	26.79%	$ 19,998,300	24.95%

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Desert Star							
341.05 Structures and Improvements	$ 1,557,800	$ 202,535	13.00%	$ 196,142	12.59%	$ 210,914	13.54%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	29,042,805	6,928,587	23.86%	6,398,394	22.03%	6,880,292	23.69%
345.05 Accessory Electric Equipment	4,084,919	514,847	12.60%	514,329	12.59%	553,066	13.54%
346.05 Miscellaneous Power Plant Equipment	291,809	37,812	12.96%	36,741	12.59%	39,509	13.54%
Total Desert Star	$ 34,977,333	$ 7,683,781	21.97%	$ 7,145,606	20.43%	$ 7,683,781	21.97%
Foothills Units							
341.05 Structures and Improvements	$ 10,906,684	$ 2,002,258	18.36%	$ 2,116,240	19.40%	$ 2,040,629	18.71%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	105,443,248	19,840,062	18.82%	20,459,309	19.40%	19,728,315	18.71%
345.05 Accessory Electric Equipment	20,815,540	3,821,391	18.36%	4,038,870	19.40%	3,894,565	18.71%
346.05 Miscellaneous Power Plant Equipment	57,708	10,594	18.36%	11,197	19.40%	10,797	18.71%
Total Foothills Units	$ 137,223,180	$ 25,674,305	18.71%	$ 26,625,616	19.40%	$ 25,674,305	18.71%
Gila Bend							
341.05 Structures and Improvements	$ 5,018,097	$ 796,443	15.87%	$ 808,219	16.11%	$ 827,381	16.49%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	89,246,612	14,814,413	16.60%	14,374,140	16.11%	14,714,928	16.49%
345.05 Accessory Electric Equipment	11,096,944	1,761,241	15.87%	1,787,284	16.11%	1,829,658	16.49%
346.05 Miscellaneous Power Plant Equipment	21,142	3,356	15.87%	3,405	16.11%	3,486	16.49%
Total Gila Bend	$ 105,382,795	$ 17,375,452	16.49%	$ 16,973,048	16.11%	$ 17,375,452	16.49%
Hyder							
341.05 Structures and Improvements	$ 6,915,232	$ 1,439,968	20.82%	$ 1,500,091	21.69%	$ 1,442,728	20.86%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	93,250,197	19,712,675	21.14%	20,495,412	21.98%	19,711,667	21.14%
345.05 Accessory Electric Equipment	22,556,482	4,868,348	21.58%	5,060,109	22.43%	4,866,610	21.58%
346.05 Miscellaneous Power Plant Equipment	206,389	47,783	23.15%	49,668	24.07%	47,769	23.14%
Total Hyder	$ 122,928,300	$ 26,068,774	21.21%	$ 27,105,279	22.05%	$ 26,068,774	21.21%

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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Legacy							
341.00 Structures and Improvements	$ 313,214	$ 210,689	67.27%	$ 171,974	54.91%	$ 343,852	109.78%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	10,452,105	6,148,103	58.82%	2,828,556	27.06%	5,655,515	54.11%
345.00 Accessory Electric Equipment	1,972,486	436,675	22.14%	398,162	20.19%	796,100	40.36%
346.00 Miscellaneous Power Plant Equipment							
Total Legacy	$ 12,737,805	$ 6,795,467	53.35%	$ 3,398,693	26.68%	$ 6,795,467	53.35%
Luke AFB							
341.05 Structures and Improvements	$ 1,488,329	$ 195,442	13.13%	$ 190,943	12.83%	$ 209,520	14.08%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	25,469,888	3,634,445	14.27%	3,267,622	12.83%	3,585,540	14.08%
345.05 Accessory Electric Equipment	1,757,020	215,719	12.28%	225,414	12.83%	247,346	14.08%
346.05 Miscellaneous Power Plant Equipment	357,678	47,152	13.18%	45,888	12.83%	50,352	14.08%
Total Luke AFB	$ 29,072,915	$ 4,092,758	14.08%	$ 3,729,867	12.83%	$ 4,092,758	14.08%
Paloma							
341.05 Structures and Improvements	$ 2,281,950	$ 564,894	24.75%	$ 606,364	26.57%	$ 565,148	24.77%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	49,207,939	12,136,521	24.66%	13,019,849	26.46%	12,134,861	24.66%
345.05 Accessory Electric Equipment	12,514,947	3,098,061	24.75%	3,325,496	26.57%	3,099,455	24.77%
346.05 Miscellaneous Power Plant Equipment	121,486	30,074	24.76%	32,281	26.57%	30,087	24.77%
Total Paloma	$ 64,126,322	$ 15,829,551	24.68%	$ 16,983,990	26.49%	$ 15,829,551	24.68%
Red Rock							
341.05 Structures and Improvements	$ 4,463,879	$ 235,358	5.27%	$ 415,961	9.32%	$ 239,284	5.36%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	72,010,410	3,796,746	5.27%	6,710,208	9.32%	3,860,082	5.36%
345.05 Accessory Electric Equipment	13,383,040	784,690	5.86%	1,247,083	9.32%	717,391	5.36%
346.05 Miscellaneous Power Plant Equipment	42,290	2,230	5.27%	3,941	9.32%	2,267	5.36%
Total Redrock	$ 89,899,619	$ 4,819,024	5.36%	$ 8,377,194	9.32%	$ 4,819,024	5.36%

ARIZONA PUBLIC SERVICE COMPANY
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Vintage Group Procedure
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Roof Tops							
341.05 Structures and Improvements	$ 1,585,418	$ 321,114	20.25%	$ 382,213	24.11%	$ 290,608	18.33%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	72,791,280	11,318,449	15.55%	14,594,440	20.05%	11,096,576	15.24%
345.05 Accessory Electric Equipment	16,921,978	2,029,160	11.99%	3,000,726	17.73%	2,281,539	13.48%
346.05 Miscellaneous Power Plant Equipment							
Total Roof Tops	$ 91,298,676	$ 13,668,723	14.97%	$ 17,977,379	19.69%	$ 13,668,723	14.97%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2018

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$ 141,937,433	$ 65,671,630	46.27%	$ 6,612,147	4.66%	$ 72,283,777	50.93%
312.00 Boiler Plant Equipment	1,491,411,135	627,611,807	42.08%	65,324,442	4.38%	692,936,249	46.46%
314.00 Turbogenerator Units	211,425,539	95,537,570	45.19%	7,545,775	3.57%	103,083,344	48.76%
315.00 Accessory Electric Equipment	117,866,116	54,701,477	46.41%	4,917,777	4.17%	59,619,255	50.58%
316.00 Miscellaneous Power Plant Equipment	84,425,866	37,308,659	44.19%	3,630,528	4.30%	40,939,187	48.49%
Total Steam Production Plant	$ 2,047,066,089	$ 880,831,143	43.03%	$ 88,030,669	4.30%	$ 968,861,812	47.33%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$ 850,120,585	$ 430,543,511	50.64%	$ (448,641)	-0.05%	$ 430,094,870	50.59%
322.00 Reactor Plant Equipment	1,187,263,758	677,419,114	57.06%	(6,439,994)	-0.54%	670,979,119	56.51%
323.00 Turbogenerator Units	405,048,258	207,144,449	51.14%	722,591	0.18%	207,867,040	51.32%
324.00 Accessory Electric Equipment	294,782,526	184,078,913	62.45%	20,041	0.01%	184,098,954	62.45%
325.00 Miscellaneous Power Plant Equipment	233,949,471	91,159,981	38.97%	(1,392,536)	-0.60%	89,767,444	38.37%
Total Nuclear Production Plant	$ 2,971,164,598	$ 1,590,345,967	53.53%	$ (7,538,539)	-0.25%	$ 1,582,807,428	53.27%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 131,575,027	$ 37,689,245	28.64%	$ (22,836)	-0.02%	$ 37,666,409	28.63%
342.00 Fuel Holders, Products and Accessories	56,786,945	25,393,083	44.72%	1,148,620	2.02%	26,541,703	46.74%
343.00 Prime Movers	655,542,039	251,052,239	38.30%	8,606,017	1.31%	259,658,256	39.61%
344.00 Generators and Devices	2,104,937,839	315,131,793	14.97%	59,050,056	2.81%	374,181,849	17.78%
345.00 Accessory Electric Equipment	247,553,984	64,016,199	25.86%	2,730,241	1.10%	66,746,440	26.96%
346.00 Miscellaneous Power Plant Equipment	34,845,144	9,313,034	26.73%	378,097	1.09%	9,691,130	27.81%
Total Other Production Plant	$ 3,231,240,978	$ 702,595,592	21.74%	$ 71,890,195	2.22%	$ 774,485,788	23.97%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$ 151,995	$ 110,605	72.77%	$ -		$ 110,605	72.77%
353.00 Station Equipment	132,434,328	29,081,145	21.96%	1,726,284	1.30%	30,807,429	23.26%
354.00 Towers and Fixtures	1,329,316	599,978	45.13%			599,978	45.13%
355.00 Poles and Fixtures	1,370,085	305,219	22.28%	61,044	4.46%	366,263	26.73%
356.00 Overhead Conductors and Devices	1,947,677	571,375	29.34%	129,756	6.66%	701,131	36.00%
Total Transmission Plant	$ 137,233,401	$ 30,668,322	22.35%	$ 1,917,083	1.40%	$ 32,585,406	23.74%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$ 93,053,192	$ 22,000,022	23.64%	$ 2,117,598	2.28%	$ 24,117,620	25.92%
362.00 Station Equipment	631,870,595	122,460,536	19.38%	11,401,422	1.80%	133,861,958	21.19%
363.00 Storage Battery Equipment	13,585,353	2,012,017	14.81%	(291,072)	-2.14%	1,720,945	12.67%
364.01 Poles, Towers and Fixtures - Wood	357,345,350	89,556,435	25.06%	18,845,425	5.27%	108,401,860	30.34%
364.02 Poles, Towers and Fixtures - Steel	323,911,866	41,735,335	12.88%	3,851,845	1.19%	45,587,180	14.07%
365.00 Overhead Conductors and Devices	468,658,341	72,981,841	15.57%	13,237,832	2.82%	86,219,673	18.40%
366.00 Underground Conduit	727,611,816	179,481,539	24.67%	23,737,793	3.26%	203,219,332	27.93%
367.00 Underground Conductors and Devices	1,863,851,442	509,438,141	27.33%	95,397,009	5.12%	604,835,151	32.45%
368.00 Line Transformers	921,018,156	233,516,753	25.35%	21,274,052	2.31%	254,790,805	27.66%
369.00 Services	447,263,911	115,930,639	25.92%	22,414,343	5.01%	138,344,982	30.93%
370.01 Meters - Electronic	17,843,353	2,677,442	15.01%	86,713	0.49%	2,764,154	15.49%
370.03 Meters - AMI	302,666,385	125,603,779	41.50%	641,949	0.21%	126,245,728	41.71%
371.00 Installations on Customers' Premises	46,529,246	10,378,468	22.31%	1,765,903	3.80%	12,144,372	26.10%
373.00 Street Lighting and Signal Systems	80,127,587	20,179,703	25.18%	3,793,900	4.73%	23,973,603	29.92%
Total Distribution Plant	$ 6,295,336,593	$ 1,547,952,649	24.59%	$ 218,274,712	3.47%	$ 1,766,227,362	28.06%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 265,654,498	$ 40,480,892	15.24%	$ 2,680,091	1.01%	$ 43,160,983	16.25%
391.CM Office Furn. and Equip. - Computer	243,545,219	111,304,198	45.70%	(674,160)	-0.28%	110,630,038	45.42%
397.00 Communication Equipment	295,372,374	103,898,962	35.18%	(583,847)	-0.20%	103,315,115	34.98%
Total Depreciable	$ 804,572,091	$ 255,684,052	31.78%	$ 1,422,084	0.18%	$ 257,106,137	31.96%
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$ 63,799,361	$ 34,177,862	53.57%	$ -		$ 34,177,862	53.57%
393.00 Stores Equipment	594,181	162,894	27.41%			162,894	27.41%
394.00 Tools, Shop and Garage Equipment	43,094,855	20,743,001	48.13%			20,743,001	48.13%
395.00 Laboratory Equipment	767,547	492,765	64.20%			492,765	64.20%
398.00 Miscellaneous Equipment	23,861,303	6,301,368	26.41%			6,301,368	26.41%
Total Amortizable	$ 132,117,247	$ 61,877,890	46.84%	$ -		$ 61,877,890	46.84%
Total General Plant	$ 936,689,338	$ 317,561,942	33.90%	$ 1,422,084	0.15%	$ 318,984,027	34.05%
TOTAL UTILITY	$ 15,618,730,997	$ 5,069,955,616	32.46%	$ 373,996,206	2.39%	$ 5,443,951,822	34.86%

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Depreciation Reserve Components
Redistributed Reserve
December 31, 2018

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$ 78,078,473	$ 37,230,474	47.68%	$ 2,475,887	3.17%	$ 39,706,361	50.85%
312.00 Boiler Plant Equipment	385,237,434	187,052,065	48.56%	12,861,133	3.34%	199,913,198	51.89%
314.00 Turbogenerator Units	85,554,772	44,770,942	52.33%	3,705,892	4.33%	48,476,834	56.66%
315.00 Accessory Electric Equipment	53,298,558	29,293,767	54.96%	2,166,088	4.06%	31,459,855	59.03%
316.00 Miscellaneous Power Plant Equipment	24,674,267	11,129,295	45.10%	837,324	3.39%	11,966,620	48.50%
Total Cholla	$ 626,843,504	$ 309,476,543	49.37%	$ 22,046,325	3.52%	$ 331,522,868	52.89%
Cholla Unit 1							
311.00 Structures and Improvements	$ 4,743,207	$ 2,975,224	62.73%	$ 243,968	5.14%	$ 3,219,192	67.87%
312.00 Boiler Plant Equipment	82,295,074	46,905,302	57.00%	3,155,773	3.83%	50,061,075	60.83%
314.00 Turbogenerator Units	27,444,492	15,315,389	55.80%	1,220,471	4.45%	16,535,860	60.25%
315.00 Accessory Electric Equipment	9,492,908	5,873,866	61.88%	476,140	5.02%	6,350,006	66.89%
316.00 Miscellaneous Power Plant Equipment	3,742,187	2,118,643	56.62%	177,966	4.76%	2,296,609	61.37%
Total Cholla Unit 1	$ 127,717,868	$ 73,188,423	57.30%	$ 5,274,318	4.13%	$ 78,462,742	61.43%
Cholla Unit 3							
311.00 Structures and Improvements	$ 13,288,725	$ 6,486,408	48.81%	$ 471,728	3.55%	$ 6,958,137	52.36%
312.00 Boiler Plant Equipment	243,068,426	112,404,775	46.24%	7,796,258	3.21%	120,201,033	49.45%
314.00 Turbogenerator Units	57,062,305	28,968,380	50.77%	2,447,994	4.29%	31,416,373	55.06%
315.00 Accessory Electric Equipment	34,899,789	19,636,921	56.27%	1,374,584	3.94%	21,011,505	60.21%
316.00 Miscellaneous Power Plant Equipment	7,009,816	3,223,950	45.99%	219,945	3.14%	3,443,895	49.13%
Total Cholla Unit 3	$ 355,329,061	$ 170,720,434	48.05%	$ 12,310,509	3.46%	$ 183,030,943	51.51%
Cholla Common							
311.00 Structures and Improvements	$ 60,046,541	$ 27,768,842	46.25%	$ 1,760,190	2.93%	$ 29,529,032	49.18%
312.00 Boiler Plant Equipment	59,873,934	27,741,988	46.33%	1,909,103	3.19%	29,651,091	49.52%
314.00 Turbogenerator Units	1,047,975	487,173	46.49%	37,427	3.57%	524,600	50.06%
315.00 Accessory Electric Equipment	8,905,861	3,782,981	42.48%	315,364	3.54%	4,098,345	46.02%
316.00 Miscellaneous Power Plant Equipment	13,922,264	5,786,702	41.56%	439,413	3.16%	6,226,116	44.72%
Total Cholla Common	$ 143,796,575	$ 65,567,686	45.60%	$ 4,461,497	3.10%	$ 70,029,184	48.70%

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Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Four Corners							
311.00 Structures and Improvements	$ 63,858,960	$ 28,441,155	44.54%	$ 4,136,260	6.48%	$ 32,577,416	51.01%
312.00 Boiler Plant Equipment	1,106,173,701	440,559,742	39.83%	52,463,309	4.74%	493,023,051	44.57%
314.00 Turbogenerator Units	125,870,767	50,766,628	40.33%	3,839,883	3.05%	54,606,511	43.38%
315.00 Accessory Electric Equipment	64,567,558	25,407,710	39.35%	2,751,689	4.26%	28,159,399	43.61%
316.00 Miscellaneous Power Plant Equipment	59,751,599	26,179,364	43.81%	2,793,204	4.67%	28,972,568	48.49%
Total Four Corners	$ 1,420,222,585	$ 571,354,599	40.23%	$ 65,984,345	4.65%	$ 637,338,944	44.88%
Four Corners Units 4-5							
311.00 Structures and Improvements	$ 39,839,762	$ 24,334,464	61.08%	$ 2,981,529	7.48%	$ 27,315,993	68.56%
312.00 Boiler Plant Equipment	1,066,430,407	429,390,184	40.26%	51,724,019	4.85%	481,114,204	45.11%
314.00 Turbogenerator Units	121,897,287	49,396,176	40.52%	3,683,372	3.02%	53,079,548	43.54%
315.00 Accessory Electric Equipment	43,201,151	21,838,684	50.55%	2,276,103	5.27%	24,114,787	55.82%
316.00 Miscellaneous Power Plant Equipment	39,853,780	20,923,130	52.50%	2,461,670	6.18%	23,384,800	58.68%
Total Four Corners Units 4-5	$ 1,311,222,387	$ 545,882,638	41.63%	$ 63,126,693	4.81%	$ 609,009,331	46.45%
Four Corners Common							
311.00 Structures and Improvements	$ 24,019,198	$ 4,106,691	17.10%	$ 1,154,731	4.81%	$ 5,261,422	21.91%
312.00 Boiler Plant Equipment	39,743,294	11,169,558	28.10%	739,289	1.86%	11,908,847	29.96%
314.00 Turbogenerator Units	3,973,480	1,370,452	34.49%	156,511	3.94%	1,526,963	38.43%
315.00 Accessory Electric Equipment	21,366,407	3,569,027	16.70%	475,586	2.23%	4,044,613	18.93%
316.00 Miscellaneous Power Plant Equipment	19,897,819	5,256,234	26.42%	331,534	1.67%	5,587,768	28.08%
Total Four Corners Common	$ 109,000,198	$ 25,471,962	23.37%	$ 2,857,651	2.62%	$ 28,329,613	25.99%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$ 850,120,585	$ 430,543,511	50.64%	$ (448,641)	-0.05%	$ 430,094,870	50.59%
322.00 Reactor Plant Equipment	1,187,263,758	677,419,114	57.06%	(6,439,994)	-0.54%	670,979,119	56.51%
323.00 Turbogenerator Units	405,048,258	207,144,449	51.14%	722,591	0.18%	207,867,040	51.32%
324.00 Accessory Electric Equipment	294,782,526	184,078,913	62.45%	20,041	0.01%	184,098,954	62.45%
325.00 Miscellaneous Power Plant Equipment	233,949,471	91,159,981	38.97%	(1,392,536)	-0.60%	89,767,444	38.37%
Total Palo Verde	$ 2,971,164,598	$ 1,590,345,967	53.53%	$ (7,538,539)	-0.25%	$ 1,582,807,428	53.27%

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Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Palo Verde Unit 1							
321.00 Structures and Improvements	$ 169,287,979	$ 111,802,712	66.04%	$ 118,837	0.07%	$ 111,921,549	66.11%
322.00 Reactor Plant Equipment	465,986,593	286,578,865	61.50%	1,588,821	0.34%	288,167,686	61.84%
323.00 Turbogenerator Units	144,321,116	78,049,150	54.08%	(1,628,715)	-1.13%	76,420,435	52.95%
324.00 Accessory Electric Equipment	121,319,415	81,733,122	67.37%	93,215	0.08%	81,826,338	67.45%
325.00 Miscellaneous Power Plant Equipment	33,599,919	20,678,507	61.54%	(145,002)	-0.43%	20,533,505	61.11%
Total Palo Verde Unit 1	$ 934,515,022	$ 578,842,355	61.94%	$ 27,157	0.00%	$ 578,869,513	61.94%
Palo Verde Unit 2							
321.00 Structures and Improvements	$ 94,477,904	$ 62,008,748	65.63%	$ 189,616	0.20%	$ 62,198,364	65.83%
322.00 Reactor Plant Equipment	248,880,636	138,091,728	55.49%	(768,858)	-0.31%	137,322,870	55.18%
323.00 Turbogenerator Units	87,819,612	45,250,943	51.53%	(664,524)	-0.76%	44,586,419	50.77%
324.00 Accessory Electric Equipment	49,752,711	31,534,404	63.38%	(1,397)	0.00%	31,533,007	63.38%
325.00 Miscellaneous Power Plant Equipment	27,865,592	16,903,904	60.66%	(79,596)	-0.29%	16,824,307	60.38%
Total Palo Verde Unit 2	$ 508,796,455	$ 293,789,726	57.74%	$ (1,324,759)	-0.26%	$ 292,464,968	57.48%
Palo Verde Unit 3							
321.00 Structures and Improvements	$167,896,725.00	$ 106,427,758	63.39%	$ 425,711	0.25%	$ 106,853,469	63.64%
322.00 Reactor Plant Equipment	436,634,437	236,185,749	54.09%	(4,436,604)	-1.02%	231,749,145	53.08%
323.00 Turbogenerator Units	167,364,071	82,447,723	49.26%	3,195,956	1.91%	85,643,680	51.17%
324.00 Accessory Electric Equipment	95,765,260	58,259,871	60.84%	(35,010)	-0.04%	58,224,861	60.80%
325.00 Miscellaneous Power Plant Equipment	29,878,581	17,385,917	58.19%	(125,745)	-0.42%	17,260,172	57.77%
Total Palo Verde Unit 3	$ 897,539,074	$ 500,707,018	55.79%	$ (975,691)	-0.11%	$ 499,731,327	55.68%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$ 233,902,104	$ 75,433,712	32.25%	$ (724,189)	-0.31%	$ 74,709,524	31.94%
322.00 Reactor Plant Equipment	454,911	68,359	15.03%	752	0.17%	69,111	15.19%
323.00 Turbogenerator Units	217,756	107,049	49.16%	(6,913)	-3.17%	100,136	45.99%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	241,107	58,245	24.16%	(216,676)	-89.87%	(158,431)	-65.71%
Total Palo Verde Water Reclamation	$ 234,815,878	$ 75,667,366	32.22%	$ (947,026)	-0.40%	$ 74,720,339	31.82%

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Palo Verde Common							
321.00 Structures and Improvements	$ 184,555,873	$ 74,870,580	40.57%	$ (458,617)	-0.25%	$ 74,411,964	40.32%
322.00 Reactor Plant Equipment	35,307,181	16,494,414	46.72%	(2,824,106)	-8.00%	13,670,308	38.72%
323.00 Turbogenerator Units	5,325,703	1,289,584	24.21%	(173,213)	-3.25%	1,116,371	20.96%
324.00 Accessory Electric Equipment	27,945,140	12,551,516	44.91%	(36,767)	-0.13%	12,514,748	44.78%
325.00 Miscellaneous Power Plant Equipment	142,364,272	36,133,408	25.38%	(825,517)	-0.58%	35,307,891	24.80%
Total Palo Verde Common	$ 395,498,169	$ 141,339,501	35.74%	$ (4,318,220)	-1.09%	$ 137,021,281	34.65%
OTHER PRODUCTION							
Combined Cycle							
341.00 Structures and Improvements	$ 63,600,586	$ 19,489,259	30.64%	$ 731,689	1.15%	$ 20,220,947	31.79%
342.00 Fuel Holders, Products and Accessories	41,829,313	17,378,212	41.55%	767,824	1.84%	18,146,036	43.38%
343.00 Prime Movers	274,702,584	83,662,701	30.46%	3,034,642	1.10%	86,697,343	31.56%
344.00 Generators and Devices	727,795,468	163,105,386	22.41%	43,647,898	6.00%	206,753,284	28.41%
345.00 Accessory Electric Equipment	78,442,697	21,832,366	27.83%	134,307	0.17%	21,966,673	28.00%
346.00 Miscellaneous Power Plant Equipment	20,741,997	5,206,878	25.10%	170,290	0.82%	5,377,167	25.92%
Total Combined Cycle	$ 1,207,112,645	$ 310,674,801	25.74%	$ 48,486,650	4.02%	$ 359,161,451	29.75%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$ 23,988,173	$ 6,221,126	25.93%	$ 330,115	1.38%	$ 6,551,241	27.31%
342.00 Fuel Holders, Products and Accessories	12,809,613	2,064,953	16.12%	20,751	0.16%	2,085,704	16.28%
343.00 Prime Movers	132,414,998	34,580,323	26.12%	(103,712)	-0.08%	34,476,612	26.04%
344.00 Generators and Devices	391,212,295	60,132,621	15.37%	31,730,415	8.11%	91,863,036	23.48%
345.00 Accessory Electric Equipment	29,897,838	6,596,589	22.06%	(295,822)	-0.99%	6,300,767	21.07%
346.00 Miscellaneous Power Plant Equipment	6,872,469	1,147,209	16.69%	97,744	1.42%	1,244,952	18.12%
Total Redhawk CC Units 1-2	$ 597,195,386	$ 110,742,821	18.54%	$ 31,779,492	5.32%	$ 142,522,314	23.87%
West Phoenix							
341.00 Structures and Improvements	$ 39,612,413	$ 13,268,133	33.49%	$ 401,573	1.01%	$ 13,669,706	34.51%
342.00 Fuel Holders, Products and Accessories	29,019,700	15,313,259	52.77%	747,072	2.57%	16,060,331	55.34%
343.00 Prime Movers	142,287,586	49,082,377	34.50%	3,138,354	2.21%	52,220,732	36.70%
344.00 Generators and Devices	336,583,173	102,972,765	30.59%	11,917,483	3.54%	114,890,248	34.13%
345.00 Accessory Electric Equipment	48,544,859	15,235,777	31.38%	430,129	0.89%	15,665,906	32.27%
346.00 Miscellaneous Power Plant Equipment	13,869,528	4,059,669	29.27%	72,546	0.52%	4,132,215	29.79%
Total West Phoenix	$ 609,917,259	$ 199,931,979	32.78%	$ 16,707,158	2.74%	$ 216,639,138	35.52%

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West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$ 366,217	$ 191,708	52.35%	$ 9,585	2.62%	$ 201,293	54.97%
342.00 Fuel Holders, Products and Accessories	22,031,967	12,683,548	57.57%	615,587	2.79%	13,299,135	60.36%
343.00 Prime Movers							
344.00 Generators and Devices	130,345,213	56,952,917	43.69%	2,920,724	2.24%	59,873,641	45.93%
345.00 Accessory Electric Equipment	32,620,455	11,143,137	34.16%	278,975	0.86%	11,422,112	35.02%
346.00 Miscellaneous Power Plant Equipment	8,073,969	3,075,908	38.10%	34,310	0.42%	3,110,218	38.52%
Total West Phoenix CC Units 1-3	$ 193,437,821	$ 84,047,218	43.45%	$ 3,859,181	2.00%	$ 87,906,399	45.44%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$ 7,035,987	$ 2,078,150	29.54%	$ 99,598	1.42%	$ 2,177,748	30.95%
342.00 Fuel Holders, Products and Accessories	4,470,010	1,929,611	43.17%	96,481	2.16%	2,026,092	45.33%
343.00 Prime Movers	49,464,010	21,971,767	44.42%	2,383,092	4.82%	24,354,859	49.24%
344.00 Generators and Devices	23,956,815	8,113,730	33.87%	432,961	1.81%	8,546,690	35.68%
345.00 Accessory Electric Equipment	552,377	142,180	25.74%	7,109	1.29%	149,289	27.03%
346.00 Miscellaneous Power Plant Equipment	942,600	173,474	18.40%	14,815	1.57%	188,289	19.98%
Total West Phoenix CC Unit 4	$ 86,421,799	$ 34,408,912	39.82%	$ 3,034,054	3.51%	$ 37,442,966	43.33%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$ 11,054,705	$ 3,205,561	29.00%	$ 180,796	1.64%	$ 3,386,356	30.63%
342.00 Fuel Holders, Products and Accessories	2,517,723	700,100	27.81%	35,005	1.39%	735,105	29.20%
343.00 Prime Movers	92,823,576	27,110,610	29.21%	755,263	0.81%	27,865,873	30.02%
344.00 Generators and Devices	182,281,145	37,906,118	20.80%	8,563,798	4.70%	46,469,917	25.49%
345.00 Accessory Electric Equipment	15,372,027	3,950,460	25.70%	144,045	0.94%	4,094,505	26.64%
346.00 Miscellaneous Power Plant Equipment	4,852,959	810,287	16.70%	23,422	0.48%	833,709	17.18%
Total West Phoenix CC Unit 5	$ 308,902,135	$ 73,683,136	23.85%	$ 9,702,329	3.14%	$ 83,385,465	26.99%
West Phoenix Common							
341.00 Structures and Improvements	$ 21,155,504	$ 7,792,714	36.84%	$ 111,594	0.53%	$ 7,904,308	37.36%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices							
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total West Phoenix Common	$ 21,155,504	$ 7,792,714	36.84%	$ 111,594	0.53%	$ 7,904,308	37.36%

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Combustion Turbine							
341.00 Structures and Improvements	$ 31,102,449	$ 11,973,816	38.50%	$ (1,250,483)	-4.02%	$ 10,723,333	34.48%
342.00 Fuel Holders, Products and Accessories	14,957,632	8,014,871	53.58%	380,796	2.55%	8,395,667	56.13%
343.00 Prime Movers	380,839,455	167,389,538	43.95%	5,571,375	1.46%	172,960,913	45.42%
344.00 Generators and Devices	689,863,781	36,607,831	5.31%	1,495,641	0.22%	38,103,473	5.52%
345.00 Accessory Electric Equipment	42,078,140	20,490,557	48.70%	887,520	2.11%	21,378,077	50.81%
346.00 Miscellaneous Power Plant Equipment	12,525,501	3,835,414	30.62%	185,097	1.48%	4,020,511	32.10%
Total Combustion Turbine	$ 1,171,366,958	$ 248,312,028	21.20%	$ 7,269,946	0.62%	$ 255,581,974	21.82%
Douglas CT							
341.00 Structures and Improvements	$ 103,952	$ (2,793)	-2.69%	$ (140)	-0.13%	$ (2,933)	-2.82%
342.00 Fuel Holders, Products and Accessories	137,759	(5,554)	-4.03%	(249)	-0.18%	(5,803)	-4.21%
343.00 Prime Movers	3,721,569	(69,666)	-1.87%	58,360	1.57%	(11,306)	-0.30%
344.00 Generators and Devices	971,924	(30,785)	-3.17%	(1,539)	-0.16%	(32,325)	-3.33%
345.00 Accessory Electric Equipment	582,402	(16,807)	-2.89%	(503)	-0.09%	(17,310)	-2.97%
346.00 Miscellaneous Power Plant Equipment	33,564	(1,353)	-4.03%	(72)	-0.21%	(1,426)	-4.25%
Total Douglas CT	$ 5,551,170	$ (126,959)	-2.29%	$ 55,856	1.01%	$ (71,102)	-1.28%
Ocotillo							
341.00 Structures and Improvements	$ 3,189,602	$ 686,931	21.54%	$ (361,780)	-11.34%	$ 325,151	10.19%
342.00 Fuel Holders, Products and Accessories	1,484,432	558,326	37.61%	26,769	1.80%	585,095	39.42%
343.00 Prime Movers	24,161,626	7,109,410	29.42%	(583,521)	-2.42%	6,525,889	27.01%
344.00 Generators and Devices	612,033,648	8,001,289	1.31%	240,793	0.04%	8,242,082	1.35%
345.00 Accessory Electric Equipment	4,017,658	1,466,858	36.51%	63,764	1.59%	1,530,622	38.10%
346.00 Miscellaneous Power Plant Equipment	950,460	417,522	43.93%	21,490	2.26%	439,012	46.19%
Total Ocotillo	$ 645,837,426	$ 18,240,335	2.82%	$ (592,484)	-0.09%	$ 17,647,852	2.73%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$ 3,189,602	$ 686,931	21.54%	$ (361,780)	-11.34%	$ 325,151	10.19%
342.00 Fuel Holders, Products and Accessories	1,484,432	558,326	37.61%	26,769	1.80%	585,095	39.42%
343.00 Prime Movers	24,161,626	7,109,410	29.42%	(583,521)	-2.42%	6,525,889	27.01%
344.00 Generators and Devices	15,486,821	5,171,973	33.40%	99,328	0.64%	5,271,301	34.04%
345.00 Accessory Electric Equipment	4,017,658	1,466,858	36.51%	63,764	1.59%	1,530,622	38.10%
346.00 Miscellaneous Power Plant Equipment	950,460	417,522	43.93%	21,490	2.26%	439,012	46.19%
Total Octillo CT Units 1-2	$ 49,290,599	$ 15,411,020	31.27%	$ (733,950)	-1.49%	$ 14,677,070	29.78%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2018

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Ocotillo CT Units 3-7							
341.00 Structures and Improvements	$ -	$ -		$ -		$ -	
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	596,546,827	2,829,316	0.47%	141,466	0.02%	2,970,782	0.50%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total Octillo CT Units 3-7	$ 596,546,827	$ 2,829,316	0.47%	$ 141,466	0.02%	$ 2,970,782	0.50%
Saguaro							
341.00 Structures and Improvements	$ 3,051,365	$ 1,275,204	41.79%	$ (253,282)	-8.30%	$ 1,021,922	33.49%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,012,839	61.66%	47,238	2.88%	1,060,077	64.54%
343.00 Prime Movers	23,292,483	7,255,405	31.15%	(382,677)	-1.64%	6,872,727	29.51%
344.00 Generators and Devices	38,498,152	16,532,172	42.94%	802,854	2.09%	17,335,026	45.03%
345.00 Accessory Electric Equipment	3,593,189	1,500,682	41.76%	64,017	1.78%	1,564,699	43.55%
346.00 Miscellaneous Power Plant Equipment	916,172	544,222	59.40%	27,795	3.03%	572,017	62.44%
Total Saguaro	$ 70,993,849	$ 28,120,523	39.61%	$ 305,945	0.43%	$ 28,426,468	40.04%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$ 3,051,365	$ 1,275,204	41.79%	$ (253,282)	-8.30%	$ 1,021,922	33.49%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,012,839	61.66%	47,238	2.88%	1,060,077	64.54%
343.00 Prime Movers	21,353,178	6,636,133	31.08%	(413,641)	-1.94%	6,222,492	29.14%
344.00 Generators and Devices	14,724,431	4,051,505	27.52%	193,188	1.31%	4,244,693	28.83%
345.00 Accessory Electric Equipment	3,269,324	1,409,969	43.13%	59,481	1.82%	1,469,450	44.95%
346.00 Miscellaneous Power Plant Equipment	916,172	544,222	59.40%	27,795	3.03%	572,017	62.44%
Total Saguaro CT Units 1-2	$ 44,956,958	$ 14,929,872	33.21%	$ (339,220)	-0.75%	$ 14,590,652	32.45%
Saguaro CT Unit 3							
341.00 Structures and Improvements	$ -	$ -		$ -		$ -	
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	1,939,305	619,272	31.93%	30,964	1.60%	650,235	33.53%
344.00 Generators and Devices	23,773,721	12,480,666	52.50%	609,666	2.56%	13,090,333	55.06%
345.00 Accessory Electric Equipment	323,865	90,713	28.01%	4,536	1.40%	95,248	29.41%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$ 26,036,891	$ 13,190,651	50.66%	$ 645,165	2.48%	$ 13,835,816	53.14%

ARIZONA PUBLIC SERVICE COMPANY
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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Sundance Units 1-10							
341.00 Structures and Improvements	$ 13,762,067	$ 6,875,422	49.96%	$ 123,899	0.90%	$ 6,999,321	50.86%
342.00 Fuel Holders, Products and Accessories	4,418,231	2,319,934	52.51%	108,792	2.46%	2,428,725	54.97%
343.00 Prime Movers	227,932,672	121,970,980	53.51%	5,914,983	2.60%	127,885,963	56.11%
344.00 Generators and Devices	13,058,506	2,928,182	22.42%	146,409	1.12%	3,074,591	23.54%
345.00 Accessory Electric Equipment	27,804,255	14,499,811	52.15%	656,678	2.36%	15,156,488	54.51%
346.00 Miscellaneous Power Plant Equipment	6,970,933	1,405,824	20.17%	70,291	1.01%	1,476,116	21.18%
Total Sun Dance Units 1-10	$ 293,946,664	$ 150,000,153	51.03%	$ 7,021,051	2.39%	$ 157,021,204	53.42%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$ 4,239,486	$ 941,631	22.21%	$ (8,065)	-0.19%	$ 933,566	22.02%
342.00 Fuel Holders, Products and Accessories	1,843,219	844,423	45.81%	34,914	1.89%	879,337	47.71%
343.00 Prime Movers	20,466,623	6,633,582	32.41%	(92,208)	-0.45%	6,541,374	31.96%
344.00 Generators and Devices	15,280,205	3,800,890	24.87%	117,668	0.77%	3,918,557	25.64%
345.00 Accessory Electric Equipment	1,525,954	666,115	43.65%	38,541	2.53%	704,655	46.18%
346.00 Miscellaneous Power Plant Equipment	1,026,473	460,544	44.87%	15,160	1.48%	475,703	46.34%
Total West Phoenix CT Units 1-2	$ 44,381,960	$ 13,347,185	30.07%	$ 106,009	0.24%	$ 13,453,194	30.31%
Yucca							
341.00 Structures and Improvements	$ 6,755,977	$ 2,197,421	32.53%	$ (751,116)	-11.12%	$ 1,446,305	21.41%
342.00 Fuel Holders, Products and Accessories	5,431,503	3,284,903	60.48%	163,332	3.01%	3,448,236	63.49%
343.00 Prime Movers	81,264,482	24,489,826	30.14%	656,439	0.81%	25,146,265	30.94%
344.00 Generators and Devices	10,021,346	5,376,085	53.65%	189,456	1.89%	5,565,541	55.54%
345.00 Accessory Electric Equipment	4,554,682	2,373,899	52.12%	65,024	1.43%	2,438,923	53.55%
346.00 Miscellaneous Power Plant Equipment	2,627,899	1,008,656	38.38%	50,433	1.92%	1,059,088	40.30%
Total Yucca	$ 110,655,889	$ 38,730,790	35.00%	$ 373,568	0.34%	$ 39,104,358	35.34%
Yucca CT Units 1-4							
341.00 Structures and Improvements	$ 5,685,548	$ 1,981,989	34.86%	$ (761,887)	-13.40%	$ 1,220,102	21.46%
342.00 Fuel Holders, Products and Accessories	3,934,860	2,890,782	73.47%	143,626	3.65%	3,034,408	77.12%
343.00 Prime Movers	12,670,962	6,905,109	54.50%	(44,850)	-0.35%	6,860,259	54.14%
344.00 Generators and Devices	9,848,867	5,344,680	54.27%	187,886	1.91%	5,532,566	56.17%
345.00 Accessory Electric Equipment	3,737,069	2,236,792	59.85%	67,813	1.81%	2,304,605	61.67%
346.00 Miscellaneous Power Plant Equipment	1,536,718	910,512	59.25%	45,526	2.96%	956,038	62.21%
Total Yucca CT Units 1-4	$ 37,414,024	$ 20,269,865	54.18%	$ (361,887)	-0.97%	$ 19,907,978	53.21%

ARIZONA PUBLIC SERVICE COMPANY
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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Yucca CT Units 5-6							
341.00 Structures and Improvements	$ 1,070,429	$ 215,432	20.13%	$ 10,772	1.01%	$ 226,203	21.13%
342.00 Fuel Holders, Products and Accessories	1,496,643	394,121	26.33%	19,706	1.32%	413,828	27.65%
343.00 Prime Movers	68,593,520	17,584,717	25.64%	701,289	1.02%	18,286,006	26.66%
344.00 Generators and Devices	172,479	31,405	18.21%	1,570	0.91%	32,975	19.12%
345.00 Accessory Electric Equipment	817,613	137,107	16.77%	(2,789)	-0.34%	134,318	16.43%
346.00 Miscellaneous Power Plant Equipment	1,091,181	98,143	8.99%	4,907	0.45%	103,051	9.44%
Total Yucca CT Units 5-6	$ 73,241,865	$ 18,460,926	25.21%	$ 735,455	1.00%	$ 19,196,381	26.21%
Solar Units							
341.00 Structures and Improvements	$ 36,871,992	$ 6,226,170	16.89%	$ 495,959	1.35%	$ 6,722,129	18.23%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	687,278,590	115,418,575	16.79%	13,906,517	2.02%	129,325,092	18.82%
345.00 Accessory Electric Equipment	127,033,147	21,693,276	17.08%	1,708,413	1.34%	23,401,690	18.42%
346.00 Miscellaneous Power Plant Equipment	1,577,646	270,742	17.16%	22,710	1.44%	293,452	18.60%
Total Solar Units	$ 852,761,375	$ 143,608,763	16.84%	$ 16,133,599	1.89%	$ 159,742,363	18.73%
Chino Valley							
341.05 Structures and Improvements	$ 527,890	$ 102,591	19.43%	$ 7,592	1.44%	$ 110,182	20.87%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	77,719,184	15,104,008	19.43%	1,117,697	1.44%	16,221,704	20.87%
345.05 Accessory Electric Equipment	6,511,784	1,265,505	19.43%	93,647	1.44%	1,359,153	20.87%
346.05 Miscellaneous Power Plant Equipment	216,504	42,076	19.43%	3,114	1.44%	45,189	20.87%
Total Chino Valley	$ 84,975,362	$ 16,514,179	19.43%	$ 1,222,049	1.44%	$ 17,736,228	20.87%
Cotton Center							
341.05 Structures and Improvements	$ 1,813,499	$ 413,749	22.81%	$ 28,135	1.55%	$ 441,884	24.37%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	62,644,922	13,985,857	22.33%	1,749,755	2.79%	15,735,612	25.12%
345.05 Accessory Electric Equipment	15,418,007	3,517,611	22.81%	239,198	1.55%	3,756,808	24.37%
346.05 Miscellaneous Power Plant Equipment	262,640	59,921	22.81%	4,075	1.55%	63,996	24.37%
Total Cotton Center	$ 80,139,068	$ 17,977,138	22.43%	$ 2,021,162	2.52%	$ 19,998,300	24.95%

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Redistributed Reserve
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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Desert Star							
341.05 Structures and Improvements	$ 1,557,800	$ 190,184	12.21%	$ 20,730	1.33%	$ 210,914	13.54%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	29,042,805	2,967,474	10.22%	3,912,818	13.47%	6,880,292	23.69%
345.05 Accessory Electric Equipment	4,084,919	498,707	12.21%	54,359	1.33%	553,066	13.54%
346.05 Miscellaneous Power Plant Equipment	291,809	35,625	12.21%	3,883	1.33%	39,509	13.54%
Total Desert Star	$ 34,977,333	$ 3,691,990	10.56%	$ 3,991,790	11.41%	$ 7,683,781	21.97%
Foothills Units							
341.05 Structures and Improvements	$ 10,906,684	$ 1,880,764	17.24%	$ 159,865	1.47%	$ 2,040,629	18.71%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	105,443,248	18,182,779	17.24%	1,545,536	1.47%	19,728,315	18.71%
345.05 Accessory Electric Equipment	20,815,540	3,589,460	17.24%	305,104	1.47%	3,894,565	18.71%
346.05 Miscellaneous Power Plant Equipment	57,708	9,951	17.24%	846	1.47%	10,797	18.71%
Total Foothills Units	$ 137,223,180	$ 23,662,954	17.24%	$ 2,011,351	1.47%	$ 25,674,305	18.71%
Gila Bend							
341.05 Structures and Improvements	$ 5,018,097	$ 750,119	14.95%	$ 77,262	1.54%	$ 827,381	16.49%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	89,246,612	13,340,823	14.95%	1,374,105	1.54%	14,714,928	16.49%
345.05 Accessory Electric Equipment	11,096,944	1,658,801	14.95%	170,857	1.54%	1,829,658	16.49%
346.05 Miscellaneous Power Plant Equipment	21,142	3,160	14.95%	326	1.54%	3,486	16.49%
Total Gila Bend	$ 105,382,795	$ 15,752,903	14.95%	$ 1,622,549	1.54%	$ 17,375,452	16.49%
Hyder							
341.05 Structures and Improvements	$ 6,915,232	$ 1,381,923	19.98%	$ 60,805	0.88%	$ 1,442,728	20.86%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	93,250,197	18,880,907	20.25%	830,760	0.89%	19,711,667	21.14%
345.05 Accessory Electric Equipment	22,556,482	4,661,504	20.67%	205,106	0.91%	4,866,610	21.58%
346.05 Miscellaneous Power Plant Equipment	206,389	45,755	22.17%	2,013	0.98%	47,769	23.14%
Total Hyder	$ 122,928,300	$ 24,970,090	20.31%	$ 1,098,684	0.89%	$ 26,068,774	21.21%

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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Legacy							
341.00 Structures and Improvements	$ 313,214	$ 344,571	110.01%	$ (719)	-0.23%	$ 343,852	109.78%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	10,452,105	5,765,051	55.16%	(109,536)	-1.05%	5,655,515	54.11%
345.00 Accessory Electric Equipment	1,972,486	844,010	42.79%	(47,910)	-2.43%	796,100	40.36%
346.00 Miscellaneous Power Plant Equipment							
Total Legacy	$ 12,737,805	$ 6,953,632	54.59%	$ (158,165)	-1.24%	$ 6,795,467	53.35%
Luke AFB							
341.05 Structures and Improvements	$ 1,488,329	$ 185,416	12.46%	$ 24,104	1.62%	$ 209,520	14.08%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	25,469,888	3,173,044	12.46%	412,496	1.62%	3,585,540	14.08%
345.05 Accessory Electric Equipment	1,757,020	218,890	12.46%	28,456	1.62%	247,346	14.08%
346.05 Miscellaneous Power Plant Equipment	357,678	44,560	12.46%	5,793	1.62%	50,352	14.08%
Total Luke AFB	$ 29,072,915	$ 3,621,910	12.46%	$ 470,848	1.62%	$ 4,092,758	14.08%
Paloma							
341.05 Structures and Improvements	$ 2,281,950	$ 520,874	22.83%	$ 44,274	1.94%	$ 565,148	24.77%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	49,207,939	11,184,203	22.73%	950,657	1.93%	12,134,861	24.66%
345.05 Accessory Electric Equipment	12,514,947	2,856,640	22.83%	242,814	1.94%	3,099,455	24.77%
346.05 Miscellaneous Power Plant Equipment	121,486	27,730	22.83%	2,357	1.94%	30,087	24.77%
Total Paloma	$ 64,126,322	$ 14,589,448	22.75%	$ 1,240,103	1.93%	$ 15,829,551	24.68%
Red Rock							
341.05 Structures and Improvements	$ 4,463,879	$ 207,172	4.64%	$ 32,112	0.72%	$ 239,284	5.36%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	72,010,410	3,342,062	4.64%	518,020	0.72%	3,860,082	5.36%
345.05 Accessory Electric Equipment	13,383,040	621,118	4.64%	96,273	0.72%	717,391	5.36%
346.05 Miscellaneous Power Plant Equipment	42,290	1,963	4.64%	304	0.72%	2,267	5.36%
Total Redrock	$ 89,899,619	$ 4,172,315	4.64%	$ 646,709	0.72%	$ 4,819,024	5.36%

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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Roof Tops							
341.05 Structures and Improvements	$ 1,585,418	$ 248,808	15.69%	$ 41,800	2.64%	$ 290,608	18.33%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	72,791,280	9,492,366	13.04%	1,604,210	2.20%	11,096,576	15.24%
345.05 Accessory Electric Equipment	16,921,978	1,961,030	11.59%	320,509	1.89%	2,281,539	13.48%
346.05 Miscellaneous Power Plant Equipment							
Total Roof Tops	$ 91,298,676	$ 11,702,205	12.82%	$ 1,966,519	2.15%	$ 13,668,723	14.97%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
311.00 Structures and Improvements	$ 208,338,936	$ 66,401,503	$ 141,937,433	-4.0%	-8.5%	$ (2,680,828)	$ (12,021,004)	$ (14,701,832)	-7.1%
312.00 Boiler Plant Equipment	1,636,735,456	145,324,321	1,491,411,135	-13.2%	-10.6%	(19,125,894)	(158,076,874)	(177,202,768)	-10.8%
314.00 Turbogenerator Units	254,737,767	43,312,228	211,425,539	-9.6%	-9.9%	(4,159,552)	(20,920,089)	(25,079,641)	-9.8%
315.00 Accessory Electric Equipment	128,645,312	10,779,196	117,866,116	-7.0%	-9.0%	(752,800)	(10,578,899)	(11,331,699)	-8.8%
316.00 Miscellaneous Power Plant Equipment	93,580,026	9,154,160	84,425,866	-10.8%	-9.7%	(986,064)	(8,196,437)	(9,182,501)	-9.8%
Total Steam Production Plant	$ 2,322,037,497	$ 274,971,408	$ 2,047,066,089	-10.1%	-10.2%	$ (27,705,138)	$ (209,793,303)	$ (237,498,441)	-10.2%
NUCLEAR PRODUCTION									
321.00 Structures and Improvements	$ 912,948,097	$ 62,827,512	$ 850,120,585	-5.3%	-0.4%	$ (3,300,703)	$ (3,231,194)	$ (6,531,898)	-0.7%
322.00 Reactor Plant Equipment	1,294,848,155	107,584,397	1,187,263,758	-19.6%	-1.0%	(21,074,780)	(12,345,034)	(33,419,814)	-2.6%
323.00 Turbogenerator Units	494,670,526	89,622,268	405,048,258	-0.5%	-0.3%	(451,681)	(1,388,052)	(1,839,733)	-0.4%
324.00 Accessory Electric Equipment	310,301,052	15,518,526	294,782,526	-6.8%	-0.4%	(1,055,997)	(1,057,811)	(2,113,808)	-0.7%
325.00 Miscellaneous Power Plant Equipment	282,680,555	48,731,084	233,949,471	-5.6%	-0.4%	(2,705,186)	(874,332)	(3,579,519)	-1.3%
Total Nuclear Production Plant	$ 3,295,448,385	$ 324,283,787	$ 2,971,164,598	-8.8%	-0.6%	$ (28,588,347)	$ (18,896,424)	$ (47,484,771)	-1.4%
OTHER PRODUCTION									
341.00 Structures and Improvements	$ 142,431,708	$ 10,856,681	$ 131,575,027	-37.7%	-6.2%	$ (4,089,200)	$ (8,161,862)	$ (12,251,063)	-8.6%
342.00 Fuel Holders, Products and Accessories	60,861,744	4,074,799	56,786,945	-11.9%	-5.0%	(486,418)	(2,839,347)	(3,325,765)	-5.5%
343.00 Prime Movers	803,601,945	148,059,906	655,542,039	-14.8%	-5.0%	(21,969,406)	(32,777,102)	(54,746,508)	-6.8%
344.00 Generators and Devices	2,472,634,936	367,697,097	2,104,937,839	26.7%	-6.5%	98,197,558	(137,295,793)	(39,098,235)	-1.6%
345.00 Accessory Electric Equipment	262,275,083	14,721,099	247,553,984	-22.4%	-7.3%	(3,292,132)	(18,136,699)	(21,428,831)	-8.2%
346.00 Miscellaneous Power Plant Equipment	38,983,932	4,138,788	34,845,144	-9.4%	-5.2%	(388,211)	(1,808,606)	(2,196,817)	-5.6%
Total Other Production Plant	$ 3,780,789,348	$ 549,548,370	$ 3,231,240,978	12.4%	-6.2%	$ 67,972,191	$ (201,019,410)	$ (133,047,219)	-3.5%
TRANSMISSION PLANT									
352.02 Structures and Improvements	$ 151,995	$ -	$ 151,995			$ -	$ -	$ -	
353.00 Station Equipment	151,555,932	19,121,604	132,434,328	-3.0%	-5.0%	(573,648)	(6,621,716)	(7,195,365)	-4.7%
354.00 Towers and Fixtures	1,329,316		1,329,316						
355.00 Poles and Fixtures	1,370,085		1,370,085		-20.0%		(274,017)	(274,017)	-20.0%
356.00 Overhead Conductors and Devices	2,086,319	138,842	1,947,677		-20.0%		(389,535)	(389,535)	-18.7%
Total Transmission Plant	$ 156,493,647	$ 19,260,246	$ 137,233,401	-3.0%	-5.3%	$ (573,648)	$ (7,285,269)	$ (7,858,917)	-5.0%
DISTRIBUTION PLANT									
361.00 Structures and Improvements	$ 95,893,785	$ 2,840,593	$ 93,053,192	-13.9%	-10.0%	$ (394,842)	$ (9,305,319)	$ (9,700,162)	-10.1%
362.00 Station Equipment	719,198,223	87,327,628	631,870,595	2.5%	-5.0%	2,183,191	(31,593,530)	(29,410,339)	-4.1%
363.00 Storage Battery Equipment	15,708,983	2,123,630	13,585,353	-16.5%		(350,399)		(350,399)	-2.2%
364.01 Poles, Towers and Fixtures - Wood	501,314,280	143,968,930	357,345,350	-18.9%	-20.0%	(27,210,128)	(71,469,070)	(98,679,198)	-19.7%
364.02 Poles, Towers and Fixtures - Steel	344,231,547	20,319,681	323,911,866	-12.3%	-10.0%	(2,499,321)	(32,391,187)	(34,890,507)	-10.1%
365.00 Overhead Conductors and Devices	556,228,215	87,569,874	468,658,341	-22.2%	-20.0%	(19,440,512)	(93,731,668)	(113,172,180)	-20.3%
366.00 Underground Conduit	772,775,737	45,163,921	727,611,816	-23.8%	-15.0%	(10,749,013)	(109,141,772)	(119,890,786)	-15.5%
367.00 Underground Conductors and Devices	2,141,262,621	277,411,179	1,863,851,442	-5.5%	-15.0%	(15,257,615)	(279,577,716)	(294,835,331)	-13.8%
368.00 Line Transformers	1,048,831,400	127,813,244	921,018,156	5.0%	-5.0%	6,390,662	(46,050,908)	(39,660,246)	-3.8%
369.00 Services	497,829,690	50,565,779	447,263,911	-22.2%	-20.0%	(11,225,603)	(89,452,782)	(100,678,385)	-20.2%
370.01 Meters - Electronic	141,440,235	123,596,882	17,843,353	0.6%		741,581		741,581	0.5%
370.03 Meters - AMI	350,263,986	47,597,601	302,666,385	2.5%		1,189,940		1,189,940	0.3%
371.00 Installations on Customers' Premises	58,078,738	11,549,492	46,529,246	-12.3%	-15.0%	(1,420,588)	(6,979,387)	(8,399,974)	-14.5%
373.00 Street Lighting and Signal Systems	96,259,099	16,131,512	80,127,587	-8.7%	-15.0%	(1,403,442)	(12,019,138)	(13,422,580)	-13.9%
Total Distribution Plant	$ 7,339,316,539	$ 1,043,979,946	$ 6,295,336,593	-7.6%	-12.4%	$ (79,446,088)	$ (781,712,477)	$ (861,158,565)	-11.7%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$ 323,500,264	$ 57,845,766	$ 265,654,498	-13.3%	-10.0%	$ (7,693,487)	$ (26,565,450)	$ (34,258,937)	-10.6%
391.CM Office Furn. and Equip. - Computer	462,857,657	219,312,438	243,545,219	-1.0%		(2,193,124)		(2,193,124)	-0.5%
397.00 Communication Equipment	395,793,945	100,421,571	295,372,374	-1.0%		(1,004,216)		(1,004,216)	-0.3%
Total Depreciable	$ 1,182,151,866	$ 377,579,775	$ 804,572,091	-2.9%	-3.3%	$ (10,890,827)	$ (26,565,450)	$ (37,456,277)	-3.2%
Amortizable									
391.FE Office Furn. and Equip. - Furniture	$ 98,805,447	$ 35,006,086	$ 63,799,361			$ -	$ -	$ -	
393.00 Stores Equipment	2,020,036	1,425,855	594,181						
394.00 Tools, Shop and Garage Equipment	62,007,562	18,912,707	43,094,855						
395.00 Laboratory Equipment	2,550,670	1,783,123	767,547						
398.00 Miscellaneous Equipment	26,398,794	2,537,491	23,861,303						
Total Amortizable	$ 191,782,509	$ 59,665,262	$ 132,117,247			$ -	$ -	$ -	
Total General Plant	$ 1,373,934,375	$ 437,245,037	$ 936,689,338	-2.5%	-2.8%	$ (10,890,827)	$ (26,565,450)	$ (37,456,277)	-2.7%
TOTAL UTILITY	$ 18,268,019,791	$ 2,649,288,794	$ 15,618,730,997	-3.0%	-8.0%	$ (79,231,858)	$ (1,245,272,333)	$ (1,324,504,190)	-7.3%
STEAM PRODUCTION (by Unit)									
Cholla									
311.00 Structures and Improvements	$ 91,708,535	$ 13,630,062	$ 78,078,473	-15.6%	-7.2%	$ (2,119,667)	$ (5,629,216)	$ (7,748,883)	-8.4%
312.00 Boiler Plant Equipment	433,345,405	48,107,971	385,237,434	-16.6%	-7.4%	(8,004,334)	(28,661,190)	(36,665,523)	-8.5%
314.00 Turbogenerator Units	107,426,775	21,872,003	85,554,772	3.0%	-7.5%	656,391	(6,434,311)	(5,777,920)	-5.4%
315.00 Accessory Electric Equipment	57,348,246	4,049,688	53,298,558	-3.7%	-7.3%	(148,692)	(3,881,024)	(4,029,716)	-7.0%
316.00 Miscellaneous Power Plant Equipment	29,039,797	4,365,530	24,674,267	-7.1%	-7.5%	(310,846)	(1,842,288)	(2,153,135)	-7.4%
Total Cholla	$ 718,868,758	$ 92,025,254	$ 626,843,504	-10.8%	-7.4%	$ (9,927,148)	$ (46,448,029)	$ (56,375,177)	-7.8%
Cholla Unit 1									
311.00 Structures and Improvements	$ 4,965,111	$ 221,904	$ 4,743,207	-7.1%	-8.2%	$ (15,755)	$ (388,943)	$ (404,698)	-8.2%
312.00 Boiler Plant Equipment	86,783,913	4,488,839	82,295,074	-72.0%	-8.4%	(3,231,964)	(6,912,786)	(10,144,750)	-11.7%
314.00 Turbogenerator Units	30,723,745	3,279,253	27,444,492	-15.6%	-8.4%	(511,563)	(2,305,337)	(2,816,901)	-9.2%
315.00 Accessory Electric Equipment	9,615,546	122,638	9,492,908	-44.9%	-8.3%	(55,064)	(787,911)	(842,976)	-8.8%
316.00 Miscellaneous Power Plant Equipment	3,751,539	9,352	3,742,187	-8.8%	-8.4%	(823)	(314,344)	(315,167)	-8.4%
Total Cholla Unit 1	$ 135,839,854	$ 8,121,986	$ 127,717,868	-47.0%	-8.4%	$ (3,815,170)	$ (10,709,322)	$ (14,524,492)	-10.7%
Cholla Unit 3									
311.00 Structures and Improvements	$ 15,376,019	$ 2,087,294	$ 13,288,725	-1.0%	-6.9%	$ (20,873)	$ (916,922)	$ (937,795)	-6.1%
312.00 Boiler Plant Equipment	278,166,241	35,097,815	243,068,426	-9.3%	-7.1%	(3,264,097)	(17,257,858)	(20,521,955)	-7.4%
314.00 Turbogenerator Units	74,764,009	17,701,704	57,062,305	6.9%	-7.1%	1,221,418	(4,051,424)	(2,830,006)	-3.8%
315.00 Accessory Electric Equipment	36,421,734	1,521,945	34,899,789	-7.1%	-7.0%	(108,058)	(2,442,985)	(2,551,043)	-7.0%
316.00 Miscellaneous Power Plant Equipment	7,458,584	448,768	7,009,816	-15.1%	-7.1%	(67,764)	(497,697)	(565,461)	-7.6%
Total Cholla Unit 3	$ 412,186,587	$ 56,857,526	$ 355,329,061	-3.9%	-7.1%	$ (2,239,374)	$ (25,166,886)	$ (27,406,260)	-6.6%
Cholla Common									
311.00 Structures and Improvements	$ 71,367,405	$ 11,320,864	$ 60,046,541	-18.4%	-7.2%	$ (2,083,039)	$ (4,323,351)	$ (6,406,390)	-9.0%
312.00 Boiler Plant Equipment	68,395,251	8,521,317	59,873,934	-17.7%	-7.5%	(1,508,273)	(4,490,545)	(5,998,818)	-8.8%
314.00 Turbogenerator Units	1,939,021	891,046	1,047,975	-6.0%	-7.4%	(53,463)	(77,550)	(131,013)	-6.8%
315.00 Accessory Electric Equipment	11,310,966	2,405,105	8,905,861	0.6%	-7.3%	14,431	(650,128)	(635,697)	-5.6%
316.00 Miscellaneous Power Plant Equipment	17,829,674	3,907,410	13,922,264	-6.2%	-7.4%	(242,259)	(1,030,248)	(1,272,507)	-7.1%
Total Cholla Common	$ 170,842,317	$ 27,045,742	$ 143,796,575	-14.3%	-7.4%	$ (3,872,604)	$ (10,571,822)	$ (14,444,425)	-8.5%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Four Corners									
311.00 Structures and Improvements	$ 116,630,401	$ 52,771,441	$ 63,858,960	-1.1%	-10.0%	$ (561,161)	$ (6,391,788)	$ (6,952,949)	-6.0%
312.00 Boiler Plant Equipment	1,203,390,051	97,216,350	1,106,173,701	-11.4%	-11.7%	(11,121,560)	(129,415,684)	(140,537,244)	-11.7%
314.00 Turbogenerator Units	147,310,992	21,440,225	125,870,767	-22.5%	-11.5%	(4,815,943)	(14,485,778)	(19,301,722)	-13.1%
315.00 Accessory Electric Equipment	71,297,066	6,729,508	64,567,558	-9.0%	-10.4%	(604,108)	(6,697,875)	(7,301,983)	-10.2%
316.00 Miscellaneous Power Plant Equipment	64,540,229	4,788,630	59,751,599	-14.1%	-10.6%	(675,218)	(6,354,149)	(7,029,367)	-10.9%
Total Four Corners	$ 1,603,168,739	$ 182,946,154	$ 1,420,222,585	-9.7%	-11.5%	$ (17,777,990)	$ (163,345,274)	$ (181,123,264)	-11.3%
Four Corners Units 4-5									
311.00 Structures and Improvements	$ 46,596,662	$ 6,756,900	$ 39,839,762	-4.9%	-11.1%	$ (331,088)	$ (4,422,214)	$ (4,753,302)	-10.2%
312.00 Boiler Plant Equipment	1,159,144,005	92,713,598	1,066,430,407	-11.0%	-11.8%	(10,198,496)	(125,838,788)	(136,037,284)	-11.7%
314.00 Turbogenerator Units	141,865,590	19,968,303	121,897,287	-24.0%	-11.6%	(4,792,393)	(14,140,085)	(18,932,478)	-13.3%
315.00 Accessory Electric Equipment	45,982,565	2,781,414	43,201,151	-20.3%	-11.3%	(564,627)	(4,881,730)	(5,446,357)	-11.8%
316.00 Miscellaneous Power Plant Equipment	42,831,405	2,977,625	39,853,780	-9.6%	-11.6%	(285,852)	(4,623,038)	(4,908,890)	-11.5%
Total Four Corners Units 4-5	$ 1,436,420,227	$ 125,197,840	$ 1,311,222,387	-12.9%	-11.7%	$ (16,172,456)	$ (153,905,855)	$ (170,078,311)	-11.8%
Four Corners Common									
311.00 Structures and Improvements	$ 70,033,739	$ 46,014,541	$ 24,019,198	-0.5%	-8.2%	$ (230,073)	$ (1,969,574)	$ (2,199,647)	-3.1%
312.00 Boiler Plant Equipment	44,246,046	4,502,752	39,743,294	-20.5%	-9.0%	(923,064)	(3,576,896)	(4,499,961)	-10.2%
314.00 Turbogenerator Units	5,445,402	1,471,922	3,973,480	-1.6%	-8.7%	(23,551)	(345,693)	(369,244)	-6.8%
315.00 Accessory Electric Equipment	25,314,501	3,948,094	21,366,407	-1.0%	-8.5%	(39,481)	(1,816,145)	(1,855,626)	-7.3%
316.00 Miscellaneous Power Plant Equipment	21,708,824	1,811,005	19,897,819	-21.5%	-8.7%	(389,366)	(1,731,110)	(2,120,476)	-9.8%
Total Four Corners Common	$ 166,748,512	$ 57,748,314	$ 109,000,198	-2.8%	-8.7%	$ (1,605,535)	$ (9,439,418)	$ (11,044,953)	-6.6%
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$ 912,948,097	$ 62,827,512	$ 850,120,585	-5.3%	-0.4%	$ (3,300,703)	$ (3,231,194)	$ (6,531,898)	-0.7%
322.00 Reactor Plant Equipment	1,294,848,155	107,584,397	1,187,263,758	-19.6%	-1.0%	(21,074,780)	(12,345,034)	(33,419,814)	-2.6%
323.00 Turbogenerator Units	494,670,526	89,622,268	405,048,258	-0.5%	-0.3%	(451,681)	(1,388,052)	(1,839,733)	-0.4%
324.00 Accessory Electric Equipment	310,301,052	15,518,526	294,782,526	-6.8%	-0.4%	(1,055,997)	(1,057,811)	(2,113,808)	-0.7%
325.00 Miscellaneous Power Plant Equipment	282,680,555	48,731,084	233,949,471	-5.6%	-0.4%	(2,705,186)	(874,332)	(3,579,519)	-1.3%
Total Palo Verde	$ 3,295,448,385	$ 324,283,787	$ 2,971,164,598	-8.8%	-0.6%	$ (28,588,347)	$ (18,896,424)	$ (47,484,771)	-1.4%
Palo Verde Unit 1									
321.00 Structures and Improvements	$ 172,221,669	$ 2,933,690	$ 169,287,979	-10.7%	-0.3%	$ (313,905)	$ (507,864)	$ (821,769)	-0.5%
322.00 Reactor Plant Equipment	501,531,369	35,544,776	465,986,593	-6.9%	-1.0%	(2,452,590)	(4,659,866)	(7,112,455)	-1.4%
323.00 Turbogenerator Units	172,195,829	27,874,713	144,321,116	-10.8%	-0.3%	(3,010,469)	(432,963)	(3,443,432)	-2.0%
324.00 Accessory Electric Equipment	124,527,284	3,207,869	121,319,415	-9.7%	-0.3%	(311,163)	(363,958)	(675,122)	-0.5%
325.00 Miscellaneous Power Plant Equipment	38,064,490	4,464,571	33,599,919	-7.7%	-0.3%	(343,772)	(100,800)	(444,572)	-1.2%
Total Palo Verde Unit 1	$ 1,008,540,641	$ 74,025,619	$ 934,515,022	-8.7%	-0.6%	$ (6,431,899)	$ (6,065,451)	$ (12,497,350)	-1.2%
Palo Verde Unit 2									
321.00 Structures and Improvements	$ 95,904,941	$ 1,427,037	$ 94,477,904	-4.7%	-0.4%	$ (67,071)	$ (377,912)	$ (444,982)	-0.5%
322.00 Reactor Plant Equipment	286,972,878	38,092,242	248,880,636	-10.4%	-1.0%	(3,961,593)	(2,488,806)	(6,450,400)	-2.2%
323.00 Turbogenerator Units	110,397,935	22,578,323	87,819,612	-6.3%	-0.3%	(1,422,434)	(263,459)	(1,685,893)	-1.5%
324.00 Accessory Electric Equipment	55,185,710	5,432,999	49,752,711	-4.2%	-0.4%	(228,186)	(199,011)	(427,197)	-0.8%
325.00 Miscellaneous Power Plant Equipment	30,206,647	2,341,055	27,865,592	-9.6%	-0.3%	(224,741)	(83,597)	(308,338)	-1.0%
Total Palo Verde Unit 2	$ 578,668,111	$ 69,871,656	$ 508,796,455	-8.4%	-0.7%	$ (5,904,025)	$ (3,412,784)	$ (9,316,810)	-1.6%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Palo Verde Unit 3									
321.00 Structures and Improvements	$ 171,038,026	$ 3,141,301	$167,896,725.00	-1.9%	-0.4%	$ (59,685)	$ (671,587)	$ (731,272)	-0.4%
322.00 Reactor Plant Equipment	468,018,931	31,384,494	436,634,437	-33.1%	-1.1%	(10,388,268)	(4,802,979)	(15,191,246)	-3.2%
323.00 Turbogenerator Units	205,365,668	38,001,597	167,364,071	11.1%	-0.4%	4,218,177	(669,456)	3,548,721	1.7%
324.00 Accessory Electric Equipment	100,396,135	4,630,875	95,765,260	-8.1%	-0.4%	(375,101)	(383,061)	(758,162)	-0.8%
325.00 Miscellaneous Power Plant Equipment	33,560,440	3,681,859	29,878,581	-9.0%	-0.4%	(331,367)	(119,514)	(450,882)	-1.3%
Total Palo Verde Unit 3	$ 978,379,200	$ 80,840,126	$ 897,539,074	-8.6%	-0.7%	$ (6,936,243)	$ (6,646,597)	$ (13,582,841)	-1.4%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$ 274,411,743	$ 40,509,639	$ 233,902,104	-4.5%	-0.4%	$ (1,822,934)	$ (935,608)	$ (2,758,542)	-1.0%
322.00 Reactor Plant Equipment	454,911		454,911		-1.1%		(5,004)	(5,004)	-1.1%
323.00 Turbogenerator Units	246,532	28,776	217,756	-51.7%	-0.4%	(14,877)	(871)	(15,748)	-6.4%
324.00 Accessory Electric Equipment									
325.00 Miscellaneous Power Plant Equipment	284,679	43,572	241,107	-724.1%	-0.4%	(315,505)	(964)	(316,469)	-111.2%
Total Palo Verde Water Reclamation	$ 275,397,865	$ 40,581,987	$ 234,815,878	-5.3%	-0.4%	$ (2,153,316)	$ (942,448)	$ (3,095,764)	-1.1%
Palo Verde Common									
321.00 Structures and Improvements	$ 199,371,718	$ 14,815,845	$ 184,555,873	-7.0%	-0.4%	$ (1,037,109)	$ (738,223)	$ (1,775,333)	-0.9%
322.00 Reactor Plant Equipment	37,870,066	2,562,885	35,307,181	-166.7%	-1.1%	(4,272,329)	(388,379)	(4,660,708)	-12.3%
323.00 Turbogenerator Units	6,464,562	1,138,859	5,325,703	-19.5%	-0.4%	(222,078)	(21,303)	(243,380)	-3.8%
324.00 Accessory Electric Equipment	30,191,923	2,246,783	27,945,140	-6.3%	-0.4%	(141,547)	(111,781)	(253,328)	-0.8%
325.00 Miscellaneous Power Plant Equipment	180,564,299	38,200,027	142,364,272	-3.9%	-0.4%	(1,489,801)	(569,457)	(2,059,258)	-1.1%
Total Palo Verde Common	$ 454,462,568	$ 58,964,399	$ 395,498,169	-12.1%	-0.5%	$ (7,162,864)	$ (1,829,143)	$ (8,992,007)	-2.0%
OTHER PRODUCTION									
Combined Cycle									
341.00 Structures and Improvements	$ 72,158,043	$ 8,557,457	$ 63,600,586	-7.4%	-5.0%	$ (634,548)	$ (3,180,029)	$ (3,814,577)	-5.3%
342.00 Fuel Holders, Products and Accessories	45,311,645	3,482,332	41,829,313	-11.4%	-5.0%	(397,713)	(2,091,466)	(2,489,179)	-5.5%
343.00 Prime Movers	395,322,948	120,620,364	274,702,584	-10.1%	-5.0%	(12,212,031)	(13,735,129)	(25,947,160)	-6.6%
344.00 Generators and Devices	1,077,589,301	349,793,833	727,795,468	27.1%	-5.0%	94,692,426	(36,389,773)	58,302,652	5.4%
345.00 Accessory Electric Equipment	88,989,834	10,547,137	78,442,697	-26.6%	-5.0%	(2,805,156)	(3,922,135)	(6,727,291)	-7.6%
346.00 Miscellaneous Power Plant Equipment	24,619,799	3,877,802	20,741,997	-8.9%	-5.0%	(345,710)	(1,037,100)	(1,382,810)	-5.6%
Total Combined Cycle	$ 1,703,991,570	$ 496,878,925	$ 1,207,112,645	15.8%	-5.0%	$ 78,297,268	$ (60,355,632)	$ 17,941,636	1.1%
Redhawk CC Units 1-2									
341.00 Structures and Improvements	$ 28,965,845	$ 4,977,672	$ 23,988,173	-3.9%	-5.0%	$ (194,129)	$ (1,199,409)	$ (1,393,538)	-4.8%
342.00 Fuel Holders, Products and Accessories	13,635,727	826,114	12,809,613	-26.6%	-5.0%	(219,746)	(640,481)	(860,227)	-6.3%
343.00 Prime Movers	218,146,099	85,731,101	132,414,998	-13.8%	-5.0%	(11,830,892)	(6,620,750)	(18,451,642)	-8.5%
344.00 Generators and Devices	663,960,762	272,748,467	391,212,295	30.5%	-5.0%	83,188,282	(19,560,615)	63,627,668	9.6%
345.00 Accessory Electric Equipment	34,717,991	4,820,153	29,897,838	-39.7%	-5.0%	(1,913,601)	(1,494,892)	(3,408,493)	-9.8%
346.00 Miscellaneous Power Plant Equipment	8,994,173	2,121,704	6,872,469		-5.0%		(343,623)	(343,623)	-3.8%
Total Redhawk CC Units 1-2	$ 968,420,597	$ 371,225,211	$ 597,195,386	18.6%	-5.0%	$ 69,029,914	$ (29,859,769)	$ 39,170,145	4.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
West Phoenix									
341.00 Structures and Improvements	$ 43,192,198	$ 3,579,785	$ 39,612,413	-12.3%	-5.0%	$ (440,419)	$ (1,980,621)	$ (2,421,039)	-5.6%
342.00 Fuel Holders, Products and Accessories	31,675,918	2,656,218	29,019,700	-6.7%	-5.0%	(177,967)	(1,450,985)	(1,628,952)	-5.1%
343.00 Prime Movers	177,176,849	34,889,263	142,287,586	-1.1%	-5.0%	(381,139)	(7,114,379)	(7,495,519)	-4.2%
344.00 Generators and Devices	413,628,539	77,045,366	336,583,173	14.9%	-5.0%	11,504,143	(16,829,159)	(5,325,015)	-1.3%
345.00 Accessory Electric Equipment	54,271,843	5,726,984	48,544,859	-15.6%	-5.0%	(891,555)	(2,427,243)	(3,318,798)	-6.1%
346.00 Miscellaneous Power Plant Equipment	15,625,626	1,756,098	13,869,528	-19.7%	-5.0%	(345,710)	(693,476)	(1,039,186)	-6.7%
Total West Phoenix	$ 735,570,973	$ 125,653,714	$ 609,917,259	7.4%	-5.0%	$ 9,267,354	$ (30,495,863)	$ (21,228,509)	-2.9%
West Phoenix CC Units 1-3									
341.00 Structures and Improvements	$ 446,816	$ 80,599	$ 366,217	-5.2%	-5.0%	$ (4,191)	$ (18,311)	$ (22,502)	-5.0%
342.00 Fuel Holders, Products and Accessories	24,688,185	2,656,218	22,031,967	-6.7%	-5.0%	(177,967)	(1,101,598)	(1,279,565)	-5.2%
343.00 Prime Movers									
344.00 Generators and Devices	160,941,427	30,596,214	130,345,213	-4.7%	-5.0%	(1,438,022)	(6,517,261)	(7,955,283)	-4.9%
345.00 Accessory Electric Equipment	37,533,943	4,913,488	32,620,455	-14.9%	-5.0%	(732,110)	(1,631,023)	(2,363,132)	-6.3%
346.00 Miscellaneous Power Plant Equipment	9,635,625	1,561,656	8,073,969	-20.1%	-5.0%	(313,893)	(403,698)	(717,591)	-7.4%
Total West Phoenix CC Units 1-3	$ 233,245,996	$ 39,808,175	$ 193,437,821	-6.7%	-5.0%	$ (2,666,182)	$ (9,671,891)	$ (12,338,073)	-5.3%
West Phoenix CC Unit 4									
341.00 Structures and Improvements	$ 7,091,465	$ 55,478	$ 7,035,987	-11.8%	-5.0%	$ (6,546)	$ (351,799)	$ (358,346)	-5.1%
342.00 Fuel Holders, Products and Accessories	4,470,010		4,470,010		-5.0%		(223,501)	(223,501)	-5.0%
343.00 Prime Movers	54,739,557	5,275,547	49,464,010	53.4%	-5.0%	2,817,142	(2,473,201)	343,942	0.6%
344.00 Generators and Devices	25,137,133	1,180,318	23,956,815	-0.4%	-5.0%	(4,721)	(1,197,841)	(1,202,562)	-4.8%
345.00 Accessory Electric Equipment	552,377		552,377		-5.0%		(27,619)	(27,619)	-5.0%
346.00 Miscellaneous Power Plant Equipment	961,129	18,529	942,600	40.0%	-5.0%	7,412	(47,130)	(39,718)	-4.1%
Total West Phoenix CC Unit 4	$ 92,951,671	$ 6,529,872	$ 86,421,799	43.1%	-5.0%	$ 2,813,286	$ (4,321,090)	$ (1,507,804)	-1.6%
West Phoenix CC Unit 5									
341.00 Structures and Improvements	$ 12,966,230	$ 1,911,525	$ 11,054,705	-2.6%	-5.0%	$ (49,700)	$ (552,735)	$ (602,435)	-4.6%
342.00 Fuel Holders, Products and Accessories	2,517,723		2,517,723		-5.0%		(125,886)	(125,886)	-5.0%
343.00 Prime Movers	122,437,292	29,613,716	92,823,576	-10.8%	-5.0%	(3,198,281)	(4,641,179)	(7,839,460)	-6.4%
344.00 Generators and Devices	227,549,979	45,268,834	182,281,145	28.6%	-5.0%	12,946,887	(9,114,057)	3,832,829	1.7%
345.00 Accessory Electric Equipment	16,185,523	813,496	15,372,027	-19.6%	-5.0%	(159,445)	(768,601)	(928,047)	-5.7%
346.00 Miscellaneous Power Plant Equipment	5,028,872	175,913	4,852,959	-22.3%	-5.0%	(39,229)	(242,648)	(281,877)	-5.6%
Total West Phoenix CC Unit 5	$ 386,685,619	$ 77,783,484	$ 308,902,135	12.2%	-5.0%	$ 9,500,232	$ (15,445,107)	$ (5,944,875)	-1.5%
West Phoenix Common									
341.00 Structures and Improvements	$ 22,687,687	$ 1,532,183	$ 21,155,504	-24.8%	-5.0%	$ (379,981)	$ (1,057,775)	$ (1,437,757)	-6.3%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices									
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment									
Total West Phoenix Common	$ 22,687,687	$ 1,532,183	$ 21,155,504	-24.8%	-5.0%	$ (379,981)	$ (1,057,775)	$ (1,437,757)	-6.3%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Combustion Turbine									
341.00 Structures and Improvements	$ 33,283,258	$ 2,180,809	$ 31,102,449	-158.3%	-5.0%	$ (3,452,402)	$ (1,555,122)	$ (5,007,525)	-15.0%
342.00 Fuel Holders, Products and Accessories	15,550,099	592,467	14,957,632	-15.0%	-5.0%	(88,705)	(747,882)	(836,587)	-5.4%
343.00 Prime Movers	408,278,997	27,439,542	380,839,455	-35.6%	-5.0%	(9,757,375)	(19,041,973)	(28,799,347)	-7.1%
344.00 Generators and Devices	694,364,057	4,500,276	689,863,781	-23.2%	-5.0%	(1,045,129)	(34,493,189)	(35,538,318)	-5.1%
345.00 Accessory Electric Equipment	45,091,428	3,013,288	42,078,140	-14.0%	-5.0%	(421,864)	(2,103,907)	(2,525,771)	-5.6%
346.00 Miscellaneous Power Plant Equipment	12,786,487	260,986	12,525,501	-16.3%	-5.0%	(42,501)	(626,275)	(668,776)	-5.2%
Total Combustion Turbine	$ 1,209,354,326	$ 37,987,368	$ 1,171,366,958	-39.0%	-5.0%	$ (14,807,976)	$ (58,568,348)	$ (73,376,324)	-6.1%
Douglas CT									
341.00 Structures and Improvements	$ 103,952	$ -	$ 103,952		-5.0%	$ -	$ (5,198)	$ (5,198)	-5.0%
342.00 Fuel Holders, Products and Accessories	160,633	22,874	137,759	-14.8%	-5.0%	(3,385)	(6,888)	(10,273)	-6.4%
343.00 Prime Movers	4,379,356	657,787	3,721,569	-308.8%	-5.0%	(2,031,246)	(186,078)	(2,217,325)	-50.6%
344.00 Generators and Devices	971,924		971,924		-5.0%		(48,596)	(48,596)	-5.0%
345.00 Accessory Electric Equipment	630,787	48,385	582,402	-33.3%	-5.0%	(16,112)	(29,120)	(45,232)	-7.2%
346.00 Miscellaneous Power Plant Equipment	40,913	7,349	33,564		-5.0%		(1,678)	(1,678)	-4.1%
Total Douglas CT	$ 6,287,565	$ 736,395	$ 5,551,170	-278.5%	-5.0%	$ (2,050,744)	$ (277,559)	$ (2,328,302)	-37.0%
Ocotillo									
341.00 Structures and Improvements	$ 3,391,617	$ 202,015	$ 3,189,602	-386.8%	-5.0%	$ (781,394)	$ (159,480)	$ (940,874)	-27.7%
342.00 Fuel Holders, Products and Accessories	1,556,145	71,713	1,484,432	-9.8%	-5.0%	(7,028)	(74,222)	(81,249)	-5.2%
343.00 Prime Movers	27,141,441	2,979,815	24,161,626	-80.8%	-5.0%	(2,407,691)	(1,208,081)	(3,615,772)	-13.3%
344.00 Generators and Devices	614,147,022	2,113,374	612,033,648	-25.3%	-5.0%	(534,684)	(30,601,682)	(31,136,366)	-5.1%
345.00 Accessory Electric Equipment	4,343,212	325,554	4,017,658	-12.7%	-5.0%	(41,345)	(200,883)	(242,228)	-5.6%
346.00 Miscellaneous Power Plant Equipment	1,026,859	76,399	950,460	-2.1%	-5.0%	(1,604)	(47,523)	(49,127)	-4.8%
Total Ocotillo	$ 651,606,296	$ 5,768,870	$ 645,837,426	-65.4%	-5.0%	$ (3,773,746)	$ (32,291,871)	$ (36,065,617)	-5.5%
Ocotillo CT Units 1-2									
341.00 Structures and Improvements	$ 3,391,617	$ 202,015	$ 3,189,602	-386.8%	-5.0%	$ (781,394)	$ (159,480)	$ (940,874)	-27.7%
342.00 Fuel Holders, Products and Accessories	1,556,145	71,713	1,484,432	-9.8%	-5.0%	(7,028)	(74,222)	(81,249)	-5.2%
343.00 Prime Movers	27,141,441	2,979,815	24,161,626	-80.8%	-5.0%	(2,407,691)	(1,208,081)	(3,615,772)	-13.3%
344.00 Generators and Devices	17,600,195	2,113,374	15,486,821	-25.3%	-5.0%	(534,684)	(774,341)	(1,309,025)	-7.4%
345.00 Accessory Electric Equipment	4,343,212	325,554	4,017,658	-12.7%	-5.0%	(41,345)	(200,883)	(242,228)	-5.6%
346.00 Miscellaneous Power Plant Equipment	1,026,859	76,399	950,460	-2.1%	-5.0%	(1,604)	(47,523)	(49,127)	-4.8%
Total Octillo CT Units 1-2	$ 55,059,469	$ 5,768,870	$ 49,290,599	-65.4%	-5.0%	$ (3,773,746)	$ (2,464,530)	$ (6,238,276)	-11.3%
Ocotillo CT Units 3-7									
341.00 Structures and Improvements	$ -	$ -	$ -			$ -	$ -	$ -	
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	596,546,827		596,546,827		-5.0%		(29,827,341)	(29,827,341)	-5.0%
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment									
Total Octillo CT Units 3-7	$ 596,546,827	$ -	$ 596,546,827		-5.0%	$ -	$ (29,827,341)	$ (29,827,341)	-5.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Saguaro									
341.00 Structures and Improvements	$ 3,394,644	$ 343,279	$ 3,051,365	-212.5%	-5.0%	$ (729,468)	$ (152,568)	$ (882,036)	-26.0%
342.00 Fuel Holders, Products and Accessories	1,788,911	146,423	1,642,488	-13.0%	-5.0%	(19,035)	(82,124)	(101,159)	-5.7%
343.00 Prime Movers	26,150,147	2,857,664	23,292,483	-54.5%	-5.0%	(1,557,427)	(1,164,624)	(2,722,051)	-10.4%
344.00 Generators and Devices	39,322,036	823,884	38,498,152	-10.4%	-5.0%	(85,463)	(1,924,908)	(2,010,371)	-5.1%
345.00 Accessory Electric Equipment	4,096,064	502,875	3,593,189	-10.1%	-5.0%	(50,790)	(179,659)	(230,450)	-5.6%
346.00 Miscellaneous Power Plant Equipment	927,807	11,635	916,172	8.6%	-5.0%	1,001	(45,809)	(44,808)	-4.8%
Total Saguaro	$ 75,679,609	$ 4,685,760	$ 70,993,849	-52.1%	-5.0%	$ (2,441,183)	$ (3,549,692)	$ (5,990,875)	-7.9%
Saguaro CT Units 1-2									
341.00 Structures and Improvements	$ 3,394,644	$ 343,279	$ 3,051,365	-212.5%	-5.0%	$ (729,468)	$ (152,568)	$ (882,036)	-26.0%
342.00 Fuel Holders, Products and Accessories	1,788,911	146,423	1,642,488	-13.0%	-5.0%	(19,035)	(82,124)	(101,159)	-5.7%
343.00 Prime Movers	24,210,842	2,857,664	21,353,178	-54.5%	-5.0%	(1,557,427)	(1,067,659)	(2,625,086)	-10.8%
344.00 Generators and Devices	15,159,080	434,649	14,724,431	-8.2%	-5.0%	(35,641)	(736,222)	(771,863)	-5.1%
345.00 Accessory Electric Equipment	3,772,199	502,875	3,269,324	-10.1%	-5.0%	(50,790)	(163,466)	(214,257)	-5.7%
346.00 Miscellaneous Power Plant Equipment	927,807	11,635	916,172	8.6%	-5.0%	1,001	(45,809)	(44,808)	-4.8%
Total Saguaro CT Units 1-2	$ 49,253,483	$ 4,296,525	$ 44,956,958	-55.7%	-5.0%	$ (2,391,361)	$ (2,247,848)	$ (4,639,209)	-9.4%
Saguaro CT Unit 3									
341.00 Structures and Improvements	$ -	$ -	$ -			$ -	$ -	$ -	
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	1,939,305		1,939,305		-5.0%		(96,965)	(96,965)	-5.0%
344.00 Generators and Devices	24,162,956	389,235	23,773,721	-12.8%	-5.0%	(49,822)	(1,188,686)	(1,238,508)	-5.1%
345.00 Accessory Electric Equipment	323,865		323,865		-5.0%		(16,193)	(16,193)	-5.0%
346.00 Miscellaneous Power Plant Equipment									
Total Saguaro CT Unit 3	$ 26,426,126	$ 389,235	$ 26,036,891	-12.8%	-5.0%	$ (49,822)	$ (1,301,845)	$ (1,351,667)	-5.1%
Sundance Units 1-10									
341.00 Structures and Improvements	$ 14,948,128	$ 1,186,061	$ 13,762,067	-28.4%	-5.0%	$ (336,841)	$ (688,103)	$ (1,024,945)	-6.9%
342.00 Fuel Holders, Products and Accessories	4,678,329	260,098	4,418,231	-8.2%	-5.0%	(21,328)	(220,912)	(242,240)	-5.2%
343.00 Prime Movers	240,967,861	13,035,189	227,932,672	-6.0%	-5.0%	(782,111)	(11,396,634)	(12,178,745)	-5.1%
344.00 Generators and Devices	13,426,260	367,754	13,058,506	-3.9%	-5.0%	(14,342)	(652,925)	(667,268)	-5.0%
345.00 Accessory Electric Equipment	28,954,852	1,150,597	27,804,255	-13.0%	-5.0%	(149,578)	(1,390,213)	(1,539,790)	-5.3%
346.00 Miscellaneous Power Plant Equipment	6,970,933		6,970,933		-5.0%		(348,547)	(348,547)	-5.0%
Total Sun Dance Units 1-10	$ 309,946,363	$ 15,999,699	$ 293,946,664	-8.2%	-5.0%	$ (1,304,201)	$ (14,697,333)	$ (16,001,534)	-5.2%
West Phoenix CT Units 1-2									
341.00 Structures and Improvements	$ 4,384,456	$ 144,970	$ 4,239,486	-82.8%	-5.0%	$ (120,035)	$ (211,974)	$ (332,009)	-7.6%
342.00 Fuel Holders, Products and Accessories	1,874,357	31,138	1,843,219	-93.0%	-5.0%	(28,958)	(92,161)	(121,119)	-6.5%
343.00 Prime Movers	25,491,477	5,024,854	20,466,623	-31.6%	-5.0%	(1,587,854)	(1,023,331)	(2,611,185)	-10.2%
344.00 Generators and Devices	15,727,259	447,054	15,280,205	-38.8%	-5.0%	(173,457)	(764,010)	(937,467)	-6.0%
345.00 Accessory Electric Equipment	2,211,261	685,307	1,525,954	-1.2%	-5.0%	(8,224)	(76,298)	(84,521)	-3.8%
346.00 Miscellaneous Power Plant Equipment	1,192,076	165,603	1,026,473	-25.3%	-5.0%	(41,898)	(51,324)	(93,221)	-7.8%
Total West Phoenix CT Units 1-2	$ 50,880,886	$ 6,498,926	$ 44,381,960	-30.2%	-5.0%	$ (1,960,426)	$ (2,219,098)	$ (4,179,524)	-8.2%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Yucca									
341.00 Structures and Improvements	$ 7,060,461	$ 304,484	$ 6,755,977	-487.6%	-5.0%	$ (1,484,664)	$ (337,799)	$ (1,822,463)	-25.8%
342.00 Fuel Holders, Products and Accessories	5,491,724	60,221	5,431,503	-14.9%	-5.0%	(8,971)	(271,575)	(280,546)	-5.1%
343.00 Prime Movers	84,148,715	2,884,233	81,264,482	-48.2%	-5.0%	(1,391,046)	(4,063,224)	(5,454,270)	-6.5%
344.00 Generators and Devices	10,769,556	748,210	10,021,346	-31.7%	-5.0%	(237,183)	(501,067)	(738,250)	-6.9%
345.00 Accessory Electric Equipment	4,855,252	300,570	4,554,682	-51.8%	-5.0%	(155,814)	(227,734)	(383,548)	-7.9%
346.00 Miscellaneous Power Plant Equipment	2,627,899		2,627,899		-5.0%		(131,395)	(131,395)	-5.0%
Total Yucca	$ 114,953,607	$ 4,297,718	$ 110,655,889	-76.3%	-5.0%	$ (3,277,677)	$ (5,532,794)	$ (8,810,472)	-7.7%
Yucca CT Units 1-4									
341.00 Structures and Improvements	$ 5,990,032	$ 304,484	$ 5,685,548	-487.6%	-5.0%	$ (1,484,664)	$ (284,277)	$ (1,768,941)	-29.5%
342.00 Fuel Holders, Products and Accessories	3,977,780	42,920	3,934,860	-18.2%	-5.0%	(7,811)	(196,743)	(204,554)	-5.1%
343.00 Prime Movers	13,457,623	786,661	12,670,962	-130.7%	-5.0%	(1,028,166)	(633,548)	(1,661,714)	-12.3%
344.00 Generators and Devices	10,597,077	748,210	9,848,867	-31.7%	-5.0%	(237,183)	(492,443)	(729,626)	-6.9%
345.00 Accessory Electric Equipment	3,890,494	153,425	3,737,069	-86.5%	-5.0%	(132,713)	(186,853)	(319,566)	-8.2%
346.00 Miscellaneous Power Plant Equipment	1,536,718		1,536,718		-5.0%		(76,836)	(76,836)	-5.0%
Total Yucca CT Units 1-4	$ 39,449,724	$ 2,035,700	$ 37,414,024	-142.0%	-5.0%	$ (2,890,537)	$ (1,870,701)	$ (4,761,238)	-12.1%
Yucca CT Units 5-6									
341.00 Structures and Improvements	$ 1,070,429	$ -	$ 1,070,429		-5.0%	$ -	$ (53,521)	$ (53,521)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,513,944	17,301	1,496,643	-6.7%	-5.0%	(1,159)	(74,832)	(75,991)	-5.0%
343.00 Prime Movers	70,691,092	2,097,572	68,593,520	-17.3%	-5.0%	(362,880)	(3,429,676)	(3,792,556)	-5.4%
344.00 Generators and Devices	172,479		172,479		-5.0%		(8,624)	(8,624)	-5.0%
345.00 Accessory Electric Equipment	964,758	147,145	817,613	-15.7%	-5.0%	(23,102)	(40,881)	(63,982)	-6.6%
346.00 Miscellaneous Power Plant Equipment	1,091,181		1,091,181		-5.0%		(54,559)	(54,559)	-5.0%
Total Yucca CT Units 5-6	$ 75,503,883	$ 2,262,018	$ 73,241,865	-17.1%	-5.0%	$ (387,141)	$ (3,662,093)	$ (4,049,234)	-5.4%
Solar Units									
341.00 Structures and Improvements	$ 36,990,407	$ 118,415	$ 36,871,992	-1.9%	-9.3%	$ (2,250)	$ (3,426,711)	$ (3,428,961)	-9.3%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	700,681,578	13,402,988	687,278,590	33.9%	-9.7%	4,550,261	(66,412,830)	(61,862,569)	-8.8%
345.00 Accessory Electric Equipment	128,193,821	1,160,674	127,033,147	-5.6%	-9.5%	(65,112)	(12,110,658)	(12,175,770)	-9.5%
346.00 Miscellaneous Power Plant Equipment	1,577,646		1,577,646		-9.2%		(145,231)	(145,231)	-9.2%
Total Solar Units	$ 867,443,452	$ 14,682,077	$ 852,761,375	30.5%	-9.6%	$ 4,482,899	$ (82,095,430)	$ (77,612,531)	-8.9%
Chino Valley									
341.05 Structures and Improvements	$ 527,890	$ -	$ 527,890		-7.4%	$ -	$ (39,064)	$ (39,064)	-7.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	77,719,184		77,719,184		-7.4%		(5,751,220)	(5,751,220)	-7.4%
345.05 Accessory Electric Equipment	6,511,784		6,511,784		-7.4%		(481,872)	(481,872)	-7.4%
346.05 Miscellaneous Power Plant Equipment	216,504		216,504		-7.4%		(16,021)	(16,021)	-7.4%
Total Chino Valley	$ 84,975,362	$ -	$ 84,975,362		-7.4%	$ -	$ (6,288,177)	$ (6,288,177)	-7.4%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Cotton Center									
341.05 Structures and Improvements	$ 1,813,499	$ -	$ 1,813,499		-6.8%	$ -	$ (123,318)	$ (123,318)	-6.8%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	63,041,671	396,749	62,644,922	275.5%	-6.8%	1,093,043	(4,259,855)	(3,166,811)	-5.0%
345.05 Accessory Electric Equipment	15,418,007		15,418,007		-6.8%		(1,048,424)	(1,048,424)	-6.8%
346.05 Miscellaneous Power Plant Equipment	262,640		262,640		-6.8%		(17,860)	(17,860)	-6.8%
Total Cotton Center	$ 80,535,817	$ 396,749	$ 80,139,068	275.5%	-6.8%	$ 1,093,043	$ (5,449,457)	$ (4,356,413)	-5.4%
Desert Star									
341.05 Structures and Improvements	$ 1,557,800	$ -	$ 1,557,800		-10.9%	$ -	$ (169,800)	$ (169,800)	-10.9%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	30,478,200	1,435,395	29,042,805	258.3%	-10.9%	3,707,625	(3,165,666)	541,960	1.8%
345.05 Accessory Electric Equipment	4,084,919		4,084,919		-10.9%		(445,256)	(445,256)	-10.9%
346.05 Miscellaneous Power Plant Equipment	291,809		291,809		-10.9%		(31,807)	(31,807)	-10.9%
Total Desert Star	$ 36,412,728	$ 1,435,395	$ 34,977,333	258.3%	-10.9%	$ 3,707,625	$ (3,812,529)	$ (104,904)	-0.3%
Foothills Units									
341.05 Structures and Improvements	$ 10,906,684	$ -	$ 10,906,684		-8.5%	$ -	$ (927,068)	$ (927,068)	-8.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	105,443,248		105,443,248		-8.5%		(8,962,676)	(8,962,676)	-8.5%
345.05 Accessory Electric Equipment	20,815,540		20,815,540		-8.5%		(1,769,321)	(1,769,321)	-8.5%
346.05 Miscellaneous Power Plant Equipment	57,708		57,708		-8.5%		(4,905)	(4,905)	-8.5%
Total Foothills Units	$ 137,223,180	$ -	$ 137,223,180		-8.5%	$ -	$ (11,663,970)	$ (11,663,970)	-8.5%
Gila Bend									
341.05 Structures and Improvements	$ 5,018,097	$ -	$ 5,018,097		-10.3%	$ -	$ (516,864)	$ (516,864)	-10.3%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	89,246,612		89,246,612		-10.3%		(9,192,401)	(9,192,401)	-10.3%
345.05 Accessory Electric Equipment	11,096,944		11,096,944		-10.3%		(1,142,985)	(1,142,985)	-10.3%
346.05 Miscellaneous Power Plant Equipment	21,142		21,142		-10.3%		(2,178)	(2,178)	-10.3%
Total Gila Bend	$ 105,382,795	$ -	$ 105,382,795		-10.3%	$ -	$ (10,854,428)	$ (10,854,428)	-10.3%
Hyder									
341.05 Structures and Improvements	$ 6,915,232	$ -	$ 6,915,232		-4.4%	$ -	$ (304,270)	$ (304,270)	-4.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	93,250,197		93,250,197		-4.4%		(4,103,009)	(4,103,009)	-4.4%
345.05 Accessory Electric Equipment	22,556,482		22,556,482		-4.4%		(992,485)	(992,485)	-4.4%
346.05 Miscellaneous Power Plant Equipment	206,389		206,389		-4.4%		(9,081)	(9,081)	-4.4%
Total Hyder	$ 122,928,300	$ -	$ 122,928,300		-4.4%	$ -	$ (5,408,845)	$ (5,408,845)	-4.4%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Legacy									
341.00 Structures and Improvements	$ 431,629	$ 118,415	$ 313,214	-1.9%	-0.2%	$ (2,250)	$ (626)	$ (2,876)	-0.7%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	21,981,316	11,529,211	10,452,105	-1.8%	-0.2%	(207,526)	(20,904)	(228,430)	-1.0%
345.00 Accessory Electric Equipment	3,124,849	1,152,363	1,972,486	-4.5%	-0.2%	(51,856)	(3,945)	(55,801)	-1.8%
346.00 Miscellaneous Power Plant Equipment									
Total Legacy	$ 25,537,794	$ 12,799,989	$ 12,737,805	-2.0%	-0.2%	$ (261,632)	$ (25,476)	$ (287,108)	-1.1%
Luke AFB									
341.05 Structures and Improvements	$ 1,488,329	$ -	$ 1,488,329		-13.0%	$ -	$ (193,483)	$ (193,483)	-13.0%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	25,469,888		25,469,888		-13.0%		(3,311,085)	(3,311,085)	-13.0%
345.05 Accessory Electric Equipment	1,757,020		1,757,020		-13.0%		(228,413)	(228,413)	-13.0%
346.05 Miscellaneous Power Plant Equipment	357,678		357,678		-13.0%		(46,498)	(46,498)	-13.0%
Total Luke AFB	$ 29,072,915	$ -	$ 29,072,915		-13.0%	$ -	$ (3,779,479)	$ (3,779,479)	-13.0%
Paloma									
341.05 Structures and Improvements	$ 2,281,950	$ -	$ 2,281,950		-8.5%	$ -	$ (193,966)	$ (193,966)	-8.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	49,207,939		49,207,939		-8.5%		(4,182,675)	(4,182,675)	-8.5%
345.05 Accessory Electric Equipment	12,514,947		12,514,947		-8.5%		(1,063,770)	(1,063,770)	-8.5%
346.05 Miscellaneous Power Plant Equipment	121,486		121,486		-8.5%		(10,326)	(10,326)	-8.5%
Total Paloma	$ 64,126,322	$ -	$ 64,126,322		-8.5%	$ -	$ (5,450,737)	$ (5,450,737)	-8.5%
Red Rock									
341.05 Structures and Improvements	$ 4,463,879	$ -	$ 4,463,879		-15.5%	$ -	$ (691,901)	$ (691,901)	-15.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	72,010,410		72,010,410		-15.5%		(11,161,614)	(11,161,614)	-15.5%
345.05 Accessory Electric Equipment	13,383,040		13,383,040		-15.5%		(2,074,371)	(2,074,371)	-15.5%
346.05 Miscellaneous Power Plant Equipment	42,290		42,290		-15.5%		(6,555)	(6,555)	-15.5%
Total Redrock	$ 89,899,619	$ -	$ 89,899,619		-15.5%	$ -	$ (13,934,441)	$ (13,934,441)	-15.5%
Roof Tops									
341.05 Structures and Improvements	$ 1,585,418	$ -	$ 1,585,418		-16.8%	$ -	$ (266,350)	$ (266,350)	-16.8%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	72,832,913	41,633	72,791,280	-103.0%	-16.9%	(42,882)	(12,301,726)	(12,344,608)	-16.9%
345.05 Accessory Electric Equipment	16,930,289	8,311	16,921,978	-159.5%	-16.9%	(13,256)	(2,859,814)	(2,873,070)	-17.0%
346.05 Miscellaneous Power Plant Equipment									
Total Roof Tops	$ 91,348,620	$ 49,944	$ 91,298,676	-112.4%	-16.9%	$ (56,138)	$ (15,427,891)	$ (15,484,029)	-17.0%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/18 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)									
Cholla									
311.00 Structures and Improvements	$ 78,078,473	$ 1,239,263	$ 76,839,210	-5.0%	-7.3%	$ (61,963)	$ (5,588,349)	$ (5,650,312)	-7.2%
312.00 Boiler Plant Equipment	385,237,434	6,047,096	379,190,338	-20.0%	-7.3%	(1,209,419)	(27,530,704)	(28,740,123)	-7.5%
314.00 Turbogenerator Units	85,554,772	1,348,879	84,205,893	-15.0%	-7.4%	(202,332)	(6,190,833)	(6,393,165)	-7.5%
315.00 Accessory Electric Equipment	53,298,558	862,259	52,436,299	-10.0%	-7.2%	(86,226)	(3,784,647)	(3,870,873)	-7.3%
316.00 Miscellaneous Power Plant Equipment	24,674,267	386,796	24,287,471	-15.0%	-7.3%	(58,019)	(1,778,174)	(1,836,193)	-7.4%
Total Cholla	$ 626,843,504	$ 9,884,294	$ 616,959,210	-16.4%	-7.3%	$ (1,617,960)	$ (44,872,707)	$ (46,490,666)	-7.4%
Cholla Unit 1									
311.00 Structures and Improvements	$ 4,743,207	$ 76,334	$ 4,666,873	-5.0%	-8.2%	$ (3,817)	$ (384,794)	$ (388,610)	-8.2%
312.00 Boiler Plant Equipment	82,295,074	1,293,908	81,001,166	-20.0%	-8.2%	(258,782)	(6,678,719)	(6,937,500)	-8.4%
314.00 Turbogenerator Units	27,444,492	430,213	27,014,279	-15.0%	-8.2%	(64,532)	(2,227,385)	(2,291,917)	-8.4%
315.00 Accessory Electric Equipment	9,492,908	152,294	9,340,614	-10.0%	-8.2%	(15,229)	(770,154)	(785,383)	-8.3%
316.00 Miscellaneous Power Plant Equipment	3,742,187	59,048	3,683,139	-15.0%	-8.2%	(8,857)	(303,683)	(312,540)	-8.4%
Total Cholla Unit 1	$ 127,717,868	$ 2,011,798	$ 125,706,070	-17.5%	-8.2%	$ (351,217)	$ (10,364,733)	$ (10,715,950)	-8.4%
Cholla Unit 3									
311.00 Structures and Improvements	$ 13,288,725	$ 212,298	$ 13,076,427	-5.0%	-6.9%	$ (10,615)	$ (905,388)	$ (916,003)	-6.9%
312.00 Boiler Plant Equipment	243,068,426	3,811,639	239,256,787	-20.0%	-6.9%	(762,328)	(16,565,712)	(17,328,040)	-7.1%
314.00 Turbogenerator Units	57,062,305	901,987	56,160,318	-15.0%	-6.9%	(135,298)	(3,888,440)	(4,023,738)	-7.1%
315.00 Accessory Electric Equipment	34,899,789	569,788	34,330,001	-10.0%	-6.9%	(56,979)	(2,376,948)	(2,433,927)	-7.0%
316.00 Miscellaneous Power Plant Equipment	7,009,816	110,840	6,898,976	-15.0%	-6.9%	(16,626)	(477,673)	(494,299)	-7.1%
Total Cholla Unit 3	$ 355,329,061	$ 5,606,552	$ 349,722,509	-17.5%	-6.9%	$ (981,845)	$ (24,214,161)	$ (25,196,006)	-7.1%
Cholla Common									
311.00 Structures and Improvements	$ 60,046,541	$ 950,630	$ 59,095,911	-5.0%	-7.3%	$ (47,532)	$ (4,298,167)	$ (4,345,698)	-7.2%
312.00 Boiler Plant Equipment	59,873,934	941,549	58,932,385	-20.0%	-7.3%	(188,310)	(4,286,273)	(4,474,583)	-7.5%
314.00 Turbogenerator Units	1,047,975	16,680	1,031,295	-15.0%	-7.3%	(2,502)	(75,008)	(77,510)	-7.4%
315.00 Accessory Electric Equipment	8,905,861	140,178	8,765,683	-10.0%	-7.3%	(14,018)	(637,546)	(651,564)	-7.3%
316.00 Miscellaneous Power Plant Equipment	13,922,264	216,908	13,705,356	-15.0%	-7.3%	(32,536)	(996,819)	(1,029,355)	-7.4%
Total Cholla Common	$ 143,796,575	$ 2,265,944	$ 141,530,631	-12.6%	-7.3%	$ (284,897)	$ (10,293,813)	$ (10,578,710)	-7.4%
Four Corners									
311.00 Structures and Improvements	$ 63,858,960	$ 3,176,134	$ 60,682,826	-5.0%	-10.3%	$ (158,807)	$ (6,233,150)	$ (6,391,957)	-10.0%
312.00 Boiler Plant Equipment	1,106,173,701	54,581,828	1,051,591,873	-20.0%	-11.3%	(10,916,366)	(118,709,465)	(129,625,831)	-11.7%
314.00 Turbogenerator Units	125,870,767	6,219,212	119,651,555	-15.0%	-11.3%	(932,882)	(13,522,713)	(14,455,594)	-11.5%
315.00 Accessory Electric Equipment	64,567,558	3,185,195	61,382,363	-10.0%	-10.4%	(318,519)	(6,388,231)	(6,706,750)	-10.4%
316.00 Miscellaneous Power Plant Equipment	59,751,599	2,950,039	56,801,560	-15.0%	-10.4%	(442,506)	(5,908,247)	(6,350,753)	-10.6%
Total Four Corners	$ 1,420,222,585	$ 70,112,408	$ 1,350,110,177	-18.2%	-11.2%	$ (12,769,079)	$ (150,761,805)	$ (163,530,885)	-11.5%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/18 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Four Corners Units 4-5									
311.00 Structures and Improvements	$ 39,839,762	$ 2,009,256	$ 37,830,506	-5.0%	-11.4%	$ (100,463)	$ (4,311,079)	$ (4,411,542)	-11.1%
312.00 Boiler Plant Equipment	1,066,430,407	52,613,656	1,013,816,751	-20.0%	-11.4%	(10,522,731)	(115,532,261)	(126,054,992)	-11.8%
314.00 Turbogenerator Units	121,897,287	6,014,910	115,882,377	-15.0%	-11.4%	(902,237)	(13,205,693)	(14,107,930)	-11.6%
315.00 Accessory Electric Equipment	43,201,151	2,146,326	41,054,825	-10.0%	-11.4%	(214,633)	(4,678,515)	(4,893,147)	-11.3%
316.00 Miscellaneous Power Plant Equipment	39,853,780	1,971,555	37,882,225	-15.0%	-11.4%	(295,733)	(4,316,973)	(4,612,706)	-11.6%
Total Four Corners Units 4-5	$ 1,311,222,387	$ 64,755,703	$ 1,246,466,684	-18.6%	-11.4%	$ (12,035,796)	$ (142,044,521)	$ (154,080,317)	-11.8%
Four Corners Common									
311.00 Structures and Improvements	$ 24,019,198	$ 1,166,878	$ 22,852,320	-5.0%	-8.4%	$ (58,344)	$ (1,922,071)	$ (1,980,415)	-8.2%
312.00 Boiler Plant Equipment	39,743,294	1,968,173	37,775,121	-20.0%	-8.4%	(393,635)	(3,177,204)	(3,570,838)	-9.0%
314.00 Turbogenerator Units	3,973,480	204,302	3,769,178	-15.0%	-8.4%	(30,645)	(317,019)	(347,665)	-8.7%
315.00 Accessory Electric Equipment	21,366,407	1,038,868	20,327,539	-10.0%	-8.4%	(103,887)	(1,709,716)	(1,813,603)	-8.5%
316.00 Miscellaneous Power Plant Equipment	19,897,819	978,484	18,919,335	-15.0%	-8.4%	(146,773)	(1,591,274)	(1,738,047)	-8.7%
Total Four Corners Common	$ 109,000,198	$ 5,356,705	$ 103,643,493	-13.7%	-8.4%	$ (733,283)	$ (8,717,285)	$ (9,450,568)	-8.7%
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$ 850,120,585	$ 61,394,832	$ 788,725,753	-5.0%		$ (3,069,742)	$ -	$ (3,069,742)	-0.4%
322.00 Reactor Plant Equipment	1,187,263,758	83,631,127	1,103,632,631	-15.0%		(12,544,669)		(12,544,669)	-1.1%
323.00 Turbogenerator Units	405,048,258	28,469,740	376,578,518	-5.0%		(1,423,487)		(1,423,487)	-0.4%
324.00 Accessory Electric Equipment	294,782,526	20,960,627	273,821,899	-5.0%		(1,048,031)		(1,048,031)	-0.4%
325.00 Miscellaneous Power Plant Equipment	233,949,471	16,727,503	217,221,968	-5.0%		(836,375)		(836,375)	-0.4%
Total Palo Verde	$ 2,971,164,598	$ 211,183,829	$ 2,759,980,769	-9.0%		$ (18,922,304)	$ -	$ (18,922,304)	-0.6%
Palo Verde Unit 1									
321.00 Structures and Improvements	$ 169,287,979	$ 11,428,174	$ 157,859,805	-5.0%		$ (571,409)	$ -	$ (571,409)	-0.3%
322.00 Reactor Plant Equipment	465,986,593	31,204,704	434,781,889	-15.0%		(4,680,706)		(4,680,706)	-1.0%
323.00 Turbogenerator Units	144,321,116	9,591,019	134,730,097	-5.0%		(479,551)		(479,551)	-0.3%
324.00 Accessory Electric Equipment	121,319,415	8,203,276	113,116,139	-5.0%		(410,164)		(410,164)	-0.3%
325.00 Miscellaneous Power Plant Equipment	33,599,919	2,260,075	31,339,844	-5.0%		(113,004)		(113,004)	-0.3%
Total Palo Verde Unit 1	$ 934,515,022	$ 62,687,248	$ 871,827,774	-10.0%		$ (6,254,833)	$ -	$ (6,254,833)	-0.7%
Palo Verde Unit 2									
321.00 Structures and Improvements	$ 94,477,904	$ 6,648,945	$ 87,828,959	-5.0%		$ (332,447)	$ -	$ (332,447)	-0.4%
322.00 Reactor Plant Equipment	248,880,636	17,260,986	231,619,650	-15.0%		(2,589,148)		(2,589,148)	-1.0%
323.00 Turbogenerator Units	87,819,612	6,067,738	81,751,874	-5.0%		(303,387)		(303,387)	-0.3%
324.00 Accessory Electric Equipment	49,752,711	3,488,305	46,264,406	-5.0%		(174,415)		(174,415)	-0.4%
325.00 Miscellaneous Power Plant Equipment	27,865,592	1,943,424	25,922,168	-5.0%		(97,171)		(97,171)	-0.3%
Total Palo Verde Unit 2	$ 508,796,455	$ 35,409,397	$ 473,387,058	-9.9%		$ (3,496,568)	$ -	$ (3,496,568)	-0.7%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/18 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Palo Verde Unit 3									
321.00 Structures and Improvements	$167,896,725.00	$ 12,669,800	$ 155,226,925	-5.0%		$ (633,490)	$ -	$ (633,490)	-0.4%
322.00 Reactor Plant Equipment	436,634,437	32,510,899	404,123,538	-15.0%		(4,876,635)		(4,876,635)	-1.1%
323.00 Turbogenerator Units	167,364,071	12,413,418	154,950,653	-5.0%		(620,671)		(620,671)	-0.4%
324.00 Accessory Electric Equipment	95,765,260	7,203,640	88,561,620	-5.0%		(360,182)		(360,182)	-0.4%
325.00 Miscellaneous Power Plant Equipment	29,878,581	2,242,657	27,635,924	-5.0%		(112,133)		(112,133)	-0.4%
Total Palo Verde Unit 3	$ 897,539,074	$ 67,040,413	$ 830,498,661	-9.8%		$ (6,603,111)	$ -	$ (6,603,111)	-0.7%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$ 233,902,104	$ 17,094,030	$ 216,808,074	-5.0%		$ (854,702)	$ -	$ (854,702)	-0.4%
322.00 Reactor Plant Equipment	454,911	32,352	422,559	-15.0%		(4,853)		(4,853)	-1.1%
323.00 Turbogenerator Units	217,756	16,416	201,340	-5.0%		(821)		(821)	-0.4%
324.00 Accessory Electric Equipment									#DIV/0!
325.00 Miscellaneous Power Plant Equipment	241,107	17,412	223,695	-5.0%		(871)		(871)	-0.4%
Total Palo Verde Water Reclamation	$ 234,815,878	$ 17,160,210	$ 217,655,668	-5.0%		$ (861,246)	$ -	$ (861,246)	-0.4%
Palo Verde Common									
321.00 Structures and Improvements	$ 184,555,873	$ 13,553,883	$ 171,001,990	-5.0%		$ (677,694)	$ -	$ (677,694)	-0.4%
322.00 Reactor Plant Equipment	35,307,181	2,622,186	32,684,995	-15.0%		(393,328)		(393,328)	-1.1%
323.00 Turbogenerator Units	5,325,703	381,150	4,944,553	-5.0%		(19,058)		(19,058)	-0.4%
324.00 Accessory Electric Equipment	27,945,140	2,065,406	25,879,734	-5.0%		(103,270)		(103,270)	-0.4%
325.00 Miscellaneous Power Plant Equipment	142,364,272	10,263,934	132,100,338	-5.0%		(513,197)		(513,197)	-0.4%
Total Palo Verde Common	$ 395,498,169	$ 28,886,560	$ 366,611,609	-5.9%		$ (1,706,547)	$ -	$ (1,706,547)	-0.4%
Solar Units									
341.00 Structures and Improvements	$ 28,540,745	$ 1,732,062	$ 26,808,683	-5.0%	-8.2%	$ (86,603)	$ (2,190,060)	$ (2,276,663)	-8.0%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	493,268,961	29,612,801	463,656,160	-5.0%	-8.0%	(1,480,640)	(37,289,707)	(38,770,347)	-7.9%
345.00 Accessory Electric Equipment	84,213,182	5,004,727	79,208,455	-5.0%	-7.4%	(250,236)	(5,869,632)	(6,119,869)	-7.3%
346.00 Miscellaneous Power Plant Equipment	1,413,870	86,899	1,326,971	-5.0%	-9.3%	(4,345)	(123,965)	(128,310)	-9.1%
Total Solar Units	$ 607,436,758	$ 36,436,490	$ 571,000,268	-5.0%	-8.0%	$ (1,821,824)	$ (45,473,364)	$ (47,295,188)	-7.8%
Chino Valley									
341.05 Structures and Improvements	$ 527,890	$ 30,855	$ 497,035	-5.0%	-7.5%	$ (1,543)	$ (37,272)	$ (38,815)	-7.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	77,719,184	4,542,686	73,176,498	-5.0%	-7.5%	(227,134)	(5,487,382)	(5,714,516)	-7.4%
345.05 Accessory Electric Equipment	6,511,784	380,614	6,131,170	-5.0%	-7.5%	(19,031)	(459,766)	(478,797)	-7.4%
346.05 Miscellaneous Power Plant Equipment	216,504	12,655	203,849	-5.0%	-7.5%	(633)	(15,286)	(15,919)	-7.4%
Total Chino Valley	$ 84,975,362	$ 4,966,810	$ 80,008,552	-5.0%	-7.5%	$ (248,340)	$ (5,999,706)	$ (6,248,046)	-7.4%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/18 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Cotton Center									
341.05 Structures and Improvements	$ 1,813,499	$ 101,649	$ 1,711,850	-5.0%	-7.0%	$ (5,082)	$ (119,094)	$ (124,176)	-6.8%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	62,644,922	3,509,896	59,135,026	-5.0%	-7.0%	(175,495)	(4,114,044)	(4,289,539)	-6.8%
345.05 Accessory Electric Equipment	15,418,007	864,197	14,553,810	-5.0%	-7.0%	(43,210)	(1,012,514)	(1,055,724)	-6.8%
346.05 Miscellaneous Power Plant Equipment	262,640	14,721	247,919	-5.0%	-7.0%	(736)	(17,248)	(17,984)	-6.8%
Total Cotton Center	$ 80,139,068	$ 4,490,463	$ 75,648,605	-5.0%	-7.0%	$ (224,523)	$ (5,262,900)	$ (5,487,423)	-6.8%
Desert Star									
341.05 Structures and Improvements	$ 1,557,800	$ 102,151	$ 1,455,649	-5.0%	-11.3%	$ (5,108)	$ (164,157)	$ (169,265)	-10.9%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	29,042,805	1,901,841	27,140,964	-5.0%	-11.3%	(95,092)	(3,060,755)	(3,155,847)	-10.9%
345.05 Accessory Electric Equipment	4,084,919	267,864	3,817,055	-5.0%	-11.3%	(13,393)	(430,459)	(443,852)	-10.9%
346.05 Miscellaneous Power Plant Equipment	291,809	19,135	272,674	-5.0%	-11.3%	(957)	(30,750)	(31,707)	-10.9%
Total Desert Star	$ 34,977,333	$ 2,290,992	$ 32,686,341	-5.0%	-11.3%	$ (114,550)	$ (3,686,121)	$ (3,800,670)	-10.9%
Foothills Units									
341.05 Structures and Improvements	$ 10,906,684	$ 663,527	$ 10,243,157	-5.0%	-8.7%	$ (33,176)	$ (896,004)	$ (929,180)	-8.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	105,443,248	6,414,818	99,028,430	-5.0%	-8.7%	(320,741)	(8,662,353)	(8,983,094)	-8.5%
345.05 Accessory Electric Equipment	20,815,540	1,266,349	19,549,191	-5.0%	-8.7%	(63,317)	(1,710,034)	(1,773,352)	-8.5%
346.05 Miscellaneous Power Plant Equipment	57,708	3,511	54,197	-5.0%	-8.7%	(176)	(4,741)	(4,916)	-8.5%
Total Foothills Units	$ 137,223,180	$ 8,348,205	$ 128,874,975	-5.0%	-8.7%	$ (417,410)	$ (11,273,132)	$ (11,690,542)	-8.5%
Gila Bend									
341.05 Structures and Improvements	$ 5,018,097	$ 317,200	$ 4,700,897	-5.0%	-10.6%	$ (15,860)	$ (500,606)	$ (516,466)	-10.3%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	89,246,612	5,641,395	83,605,217	-5.0%	-10.6%	(282,070)	(8,903,253)	(9,185,323)	-10.3%
345.05 Accessory Electric Equipment	11,096,944	701,452	10,395,492	-5.0%	-10.6%	(35,073)	(1,107,032)	(1,142,105)	-10.3%
346.05 Miscellaneous Power Plant Equipment	21,142	1,336	19,806	-5.0%	-10.6%	(67)	(2,109)	(2,176)	-10.3%
Total Gila Bend	$ 105,382,795	$ 6,661,385	$ 98,721,410	-5.0%	-10.6%	$ (333,069)	$ (10,513,001)	$ (10,846,070)	-10.3%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/18 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Hyder									
341.05 Structures and Improvements	$ 6,915,232	$ 404,066	$ 6,511,166	-5.0%	-4.4%	$ (20,203)	$ (284,224)	$ (304,427)	-4.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	93,250,197	5,450,161	87,800,036	-5.0%	-4.4%	(272,508)	(3,832,622)	(4,105,130)	-4.4%
345.05 Accessory Electric Equipment	22,556,482	1,318,912	21,237,570	-5.0%	-4.4%	(65,946)	(927,056)	(993,002)	-4.4%
346.05 Miscellaneous Power Plant Equipment	206,389	12,087	194,302	-5.0%	-4.4%	(604)	(8,482)	(9,086)	-4.4%
Total Hyder	$ 122,928,300	$ 7,185,226	$ 115,743,074	-5.0%	-4.4%	$ (359,261)	$ (5,052,384)	$ (5,411,645)	-4.4%
Legacy									
341.00 Structures and Improvements	$ 313,214	$ 15,019	$ 298,195	-5.0%		$ (751)	$ -	$ (751)	-0.2%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	10,452,105	481,841	9,970,264	-5.0%		(24,092)		(24,092)	-0.2%
345.00 Accessory Electric Equipment	1,972,486	90,124	1,882,362	-5.0%		(4,506)		(4,506)	-0.2%
346.00 Miscellaneous Power Plant Equipment									
Total Legacy	$ 12,737,805	$ 586,984	$ 12,150,821	-5.0%		$ (29,349)	$ -	$ (29,349)	-0.2%
Luke AFB									
341.05 Structures and Improvements	$ 1,488,329	$ 97,596	$ 1,390,733	-5.0%	-13.6%	$ (4,880)	$ (188,703)	$ (193,583)	-13.0%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	25,469,888	1,670,161	23,799,727	-5.0%	-13.6%	(83,508)	(3,229,297)	(3,312,805)	-13.0%
345.05 Accessory Electric Equipment	1,757,020	115,215	1,641,805	-5.0%	-13.6%	(5,761)	(222,771)	(228,531)	-13.0%
346.05 Miscellaneous Power Plant Equipment	357,678	23,454	334,224	-5.0%	-13.6%	(1,173)	(45,350)	(46,522)	-13.0%
Total Luke AFB	$ 29,072,915	$ 1,906,426	$ 27,166,489	-5.0%	-13.6%	$ (95,321)	$ (3,686,121)	$ (3,781,442)	-13.0%
Paloma									
341.05 Structures and Improvements	$ 2,281,950	$ 127,906	$ 2,154,044	-5.0%	-8.7%	$ (6,395)	$ (187,281)	$ (193,676)	-8.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	49,207,939	2,757,957	46,449,982	-5.0%	-8.7%	(137,898)	(4,038,540)	(4,176,438)	-8.5%
345.05 Accessory Electric Equipment	12,514,947	701,477	11,813,470	-5.0%	-8.7%	(35,074)	(1,027,109)	(1,062,182)	-8.5%
346.05 Miscellaneous Power Plant Equipment	121,486	6,809	114,677	-5.0%	-8.7%	(340)	(9,970)	(10,311)	-8.5%
Total Paloma	$ 64,126,322	$ 3,594,149	$ 60,532,173	-5.0%	-8.7%	$ (179,707)	$ (5,262,900)	$ (5,442,607)	-8.5%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/18 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Red Rock									
341.05 Structures and Improvements	$ 4,463,879	$ 303,208	$ 4,160,671	-5.0%	-16.3%	$ (15,160)	$ (678,878)	$ (694,038)	-15.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	72,010,410	4,891,286	67,119,124	-5.0%	-16.3%	(244,564)	(10,951,522)	(11,196,086)	-15.5%
345.05 Accessory Electric Equipment	13,383,040	909,039	12,474,001	-5.0%	-16.3%	(45,452)	(2,035,326)	(2,080,778)	-15.5%
346.05 Miscellaneous Power Plant Equipment	42,290	2,873	39,417	-5.0%	-16.3%	(144)	(6,432)	(6,575)	-15.5%
Total Redrock	$ 89,899,619	$ 6,106,405	$ 83,793,214	-5.0%	-16.3%	$ (305,320)	$ (13,672,157)	$ (13,977,477)	-15.5%
Roof Tops									
341.05 Structures and Improvements	$ 1,585,418	$ 92,620	$ 1,492,798	-5.0%	-17.6%	$ (4,631)	$ (262,497)	$ (267,128)	-16.8%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	72,791,280	4,239,860	68,551,420	-5.0%	-17.6%	(211,993)	(12,054,237)	(12,266,230)	-16.9%
345.05 Accessory Electric Equipment	16,921,978	983,968	15,938,010	-5.0%	-17.6%	(49,198)	(2,802,576)	(2,851,774)	-16.9%
346.05 Miscellaneous Power Plant Equipment									
Total Roof Tops	$ 91,298,676	$ 5,316,448	$ 85,982,228	-5.0%	-17.6%	$ (265,822)	$ (15,119,310)	$ (15,385,133)	-16.9%

ARIZONA PUBLIC SERVICE COMPANY
Dismantlement Costs
Steam Production

Statement G

Unit	Owned MW Capacity	Cost per kW	Estimated Cost	Final Retirements	Distributed Cost	Year of Study	Inflation Rate	Year Spent	Trended Cost	Accrual Rate
A	B	C	D	E		F	G	H	I	J=I/E
Cholla										
1	116	95	$ 11,033,863	$ 125,706,070	$ 8,502,691	2015	2.00%	2025	$ 10,364,733	8.2%
3	271	95	25,777,386	349,722,509	19,864,046	2015	2.00%	2025	24,214,161	6.9%
C			0	141,530,631	8,444,512	2015	2.00%	2025	10,293,813	7.3%
	387	95	$ 36,811,249	$ 616,959,210	$ 36,811,249				$ 44,872,707	7.3%
	Allocated to Common:		8,444,512							
	Allocated to Units:		$ 28,366,737							
Four Corners										
4-5	970	93	$ 90,078,373	$ 1,246,466,684		2015	2.00%	2038	$ 142,044,521	11.4%
C			5,528,118	103,643,493		2015	2.00%	2038	8,717,285	8.4%
	970	99	$ 95,606,491	$ 1,350,110,177					$ 150,761,805	11.2%
Solar Sites										
Chino Valley	19	185	$ 3,515,000	$ 80,008,552		2015	2.00%	2042	$ 5,999,706	7.5%
Cotton Center	17	185	3,145,000	75,648,605		2015	2.00%	2041	5,262,900	7.0%
Desart Star	11	185	2,035,000	32,686,341		2015	2.00%	2045	3,686,121	11.3%
Foothills	35	185	6,475,000	128,874,975		2015	2.00%	2043	11,273,132	8.7%
Gila Bend	32	185	5,920,000	98,721,410		2015	2.00%	2044	10,513,001	10.6%
Hyder	16	185	2,960,000	115,743,074		2015	2.00%	2042	5,052,384	4.4%
Legacy			0	12,150,821		2015	2.00%	2037	0	0.0%
Luke AFB	11	185	2,035,000	27,166,489		2015	2.00%	2045	3,686,121	13.6%
Paloma	17	185	3,145,000	60,532,173		2015	2.00%	2041	5,262,900	8.7%
Red Rock	40	185	7,400,000	83,793,214		2015	2.00%	2046	13,672,157	16.3%
Roof Tops			9,400,000	85,982,228		2018	2.00%	2042	15,119,310	17.6%
	198	232.475	$ 46,030,000	$ 801,307,883					$ 79,527,731	9.9%

ARIZONA PUBLIC SERVICE COMPANY
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Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
311.00 Structures and Improvements									23.47	10.98	-7.1	-8.5
312.00 Boiler Plant Equipment									24.10	14.83	-10.8	-10.6
314.00 Turbogenerator Units									24.08	13.13	-9.8	-9.9
315.00 Accessory Electric Equipment									26.55	13.09	-8.8	-9.0
316.00 Miscellaneous Power Plant Equipment									24.43	13.80	-9.8	-9.7
Total Steam Production Plant									24.20	14.24	-10.2	-10.2
NUCLEAR PRODUCTION												
321.00 Structures and Improvements									45.35	26.75	-0.7	-0.4
322.00 Reactor Plant Equipment									46.35	25.94	-2.6	-1.0
323.00 Turbogenerator Units									42.95	26.01	-0.4	-0.3
324.00 Accessory Electric Equipment									50.24	25.98	-0.7	-0.4
325.00 Miscellaneous Power Plant Equipment									38.90	26.94	-1.3	-0.4
Total Nuclear Production Plant									45.24	26.28	-1.4	-0.6
OTHER PRODUCTION												
341.00 Structures and Improvements									26.37	18.48	-8.6	-6.2
342.00 Fuel Holders, Products and Accessories									27.20	14.18	-5.5	-5.0
343.00 Prime Movers									28.66	17.38	-6.8	-5.0
344.00 Generators and Devices									26.98	22.18	-1.6	-6.5
345.00 Accessory Electric Equipment									26.00	18.87	-8.2	-7.3
346.00 Miscellaneous Power Plant Equipment									22.60	15.93	-5.6	-5.2
Total Other Production Plant									27.15	20.62	-3.5	-6.2
TRANSMISSION PLANT												
352.02 Structures and Improvements	50.00	R4	51.64	12.17			50.00	R4	52.37	10.25		
353.00 Station Equipment	53.00	R1.5	53.86	41.27	-4.50	-5.0	53.00	R1.5	53.77	40.72	-4.7	-5.0
354.00 Towers and Fixtures	60.00	R3	60.47	32.86			60.00	R3	60.66	30.40		
355.00 Poles and Fixtures	55.00	R1.5	55.37	44.16	-20.00	-20.0	55.00	R1.5	55.56	41.88	-20.0	-20.0
356.00 Overhead Conductors and Devices	60.00	R3	59.50	42.77	-18.7	-20.0	60.00	R3	59.37	40.12	-18.7	-20.0
Total Transmission Plant									53.92	40.60	-5.0	-5.3

ARIZONA PUBLIC SERVICE COMPANY
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Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
DISTRIBUTION PLANT												
361.00 Structures and Improvements	60.00	R3	59.90	48.10	-5.1	-5.0	60.00	R3	59.89	47.27	-10.1	-10.0
362.00 Station Equipment	43.00	L0.5	43.08	35.03	-3.8	-5.0	45.00	L0.5	45.04	37.26	-4.1	-5.0
363.00 Storage Battery Equipment	10.00	S3	10.00	6.51			10.00	S3	10.00	8.68	-2.2	
364.01 Poles, Towers and Fixtures - Wood	45.00	L0	44.55	34.73	-9.3	-10.0	45.00	L0	44.59	34.63	-19.7	-20.0
364.02 Poles, Towers and Fixtures - Steel	50.00	R0.5	50.04	44.99	-10.0	-10.0	50.00	R0.5	50.07	44.32	-10.1	-10.0
365.00 Overhead Conductors and Devices	50.00	SC	49.88	42.18	-10.1	-10.0	50.00	SC	49.93	43.00	-20.3	-20.0
366.00 Underground Conduit	60.00	L1	59.99	47.99	-10.4	-10.0	60.00	L1	60.04	46.84	-15.5	-15.0
367.00 Underground Conductors and Devices	40.00	L1	39.80	30.52	-9.0	-10.0	40.00	L1	39.90	30.18	-13.8	-15.0
368.00 Line Transformers	55.00	L1	55.07	43.00	-3.7	-5.0	55.00	L1	55.05	42.61	-3.8	-5.0
369.00 Services	55.00	L1	55.36	42.33	-19.8	-20.0	55.00	L1	55.45	42.64	-20.2	-20.0
370.01 Meters - Electronic	20.00	SC	17.52	15.30	0.5		20.00	SC	16.45	14.25	0.5	
370.03 Meters - AMI	20.00	SC	20.20	17.79	0.4		15.00	R3	14.87	9.37	0.3	
371.00 Installations on Customers' Premises	45.00	L0	44.99	36.69	-14.8	-15.0	45.00	L0	45.07	36.11	-14.5	-15.0
373.00 Street Lighting and Signal Systems	55.00	L0.5	54.49	42.84	-10.5	-12.0	55.00	L0.5	54.53	42.29	-13.9	-15.0
Total Distribution Plant									42.43	33.13	-11.7	-12.4
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	40.00	L1	39.90	32.65	-6.6	-5.0	40.00	L1	39.86	33.85	-10.6	-10.0
391.CM Office Furn. and Equip. - Computer	8.00	L3	7.95	4.77	-0.2		8.00	L3	8.16	4.47	-0.5	
397.00 Communication Equipment	21.00	L2	21.02	14.54	-0.1		21.00	L2	21.06	13.73	-0.3	
Total Depreciable									15.92	10.91	-3.2	-3.3
Amortizable												
391.FE Office Furn. and Equip. - Furniture	20.00	SQ	20.00	10.99			20.00	SQ	20.00	9.29		
393.00 Stores Equipment	20.00	SQ	20.00	14.20			20.00	SQ	20.00	14.52		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	11.54			20.00	SQ	20.00	10.37		
395.00 Laboratory Equipment	20.00	SQ	20.00	9.74			20.00	SQ	20.00	7.16		
398.00 Miscellaneous Equipment	24.00	SQ	24.00	18.64			24.00	SQ	24.00	17.66		
Total Amortizable									20.62	10.96		
Total General Plant									16.45	10.92	-2.7	-2.8
TOTAL UTILITY									32.73	23.11	-7.3	-8.0

ARIZONA PUBLIC SERVICE COMPANY
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Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION (by Unit)												
Cholla												
311.00 Structures and Improvements									20.20	6.45	-8.4	-7.2
312.00 Boiler Plant Equipment									18.69	6.45	-8.5	-7.4
314.00 Turbogenerator Units									20.81	6.45	-5.4	-7.5
315.00 Accessory Electric Equipment									25.48	6.44	-7.0	-7.3
316.00 Miscellaneous Power Plant Equipment									17.23	6.45	-7.4	-7.5
Total Cholla									19.52	6.45	-7.8	-7.4
Cholla Unit 1												
311.00 Structures and Improvements	2025	200-SC	23.80	9.38	-8.3	-8.4	2025	200-SC	23.89	6.44	-8.2	-8.2
312.00 Boiler Plant Equipment	2025	200-SC	19.88	9.38	-11.7	-8.7	2025	200-SC	19.18	6.45	-11.7	-8.4
314.00 Turbogenerator Units	2025	200-SC	18.39	9.38	-9.3	-8.6	2025	200-SC	18.42	6.45	-9.2	-8.4
315.00 Accessory Electric Equipment	2025	200-SC	22.99	9.38	-9.0	-8.5	2025	200-SC	23.08	6.45	-8.8	-8.3
316.00 Miscellaneous Power Plant Equipment	2025	200-SC	25.29	9.38	-8.6	-8.6	2025	200-SC	18.93	6.45	-8.4	-8.4
Total Cholla Unit 1									19.39	6.45	-10.7	-8.4
Cholla Unit 3												
311.00 Structures and Improvements	2025	200-SC	20.30	9.38	-6.2	-7.0	2025	200-SC	20.30	6.45	-6.1	-6.9
312.00 Boiler Plant Equipment	2025	200-SC	18.70	9.38	-7.6	-7.4	2025	200-SC	18.24	6.45	-7.4	-7.1
314.00 Turbogenerator Units	2025	200-SC	22.42	9.38	-3.9	-7.2	2025	200-SC	22.21	6.45	-3.8	-7.1
315.00 Accessory Electric Equipment	2025	200-SC	30.24	9.38	-7.1	-7.1	2025	200-SC	30.16	6.44	-7.0	-7.0
316.00 Miscellaneous Power Plant Equipment	2025	200-SC	18.97	9.38	-7.2	-7.2	2025	200-SC	18.06	6.45	-7.6	-7.1
Total Cholla Unit 3									19.64	6.45	-6.6	-7.1
Cholla Common												
311.00 Structures and Improvements	2025	200-SC	20.45	9.38	-6.8	-7.4	2025	200-SC	19.93	6.45	-9.0	-7.2
312.00 Boiler Plant Equipment	2025	200-SC	19.92	9.38	-8.9	-7.7	2025	200-SC	20.01	6.45	-8.8	-7.5
314.00 Turbogenerator Units	2025	200-SC	14.13	9.39	-7.1	-7.6	2025	200-SC	20.15	6.45	-6.8	-7.4
315.00 Accessory Electric Equipment	2025	200-SC	19.82	9.38	-5.2	-7.5	2025	200-SC	17.03	6.45	-5.6	-7.3
316.00 Miscellaneous Power Plant Equipment	2025	200-SC	16.49	9.39	-7.3	-7.6	2025	200-SC	16.45	6.45	-7.1	-7.4
Total Cholla Common									19.36	6.45	-8.5	-7.4

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Four Corners												
311.00 Structures and Improvements									29.26	19.01	-6.0	-10.0
312.00 Boiler Plant Equipment									26.80	19.01	-11.7	-11.7
314.00 Turbogenerator Units									26.95	19.01	-13.1	-11.5
315.00 Accessory Electric Equipment									27.51	19.01	-10.2	-10.4
316.00 Miscellaneous Power Plant Equipment									29.53	19.01	-10.9	-10.6
Total Four Corners									27.05	19.01	-11.3	-11.5
Four Corners Units 4-5												
311.00 Structures and Improvements	2038	200-SC	38.42	21.84	-18.6	-19.7	2038	200-SC	33.84	19.00	-10.2	-11.1
312.00 Boiler Plant Equipment	2038	200-SC	42.42	21.83	-19.1	-20.6	2038	200-SC	26.74	19.01	-11.7	-11.8
314.00 Turbogenerator Units	2038	200-SC	40.60	21.83	-19.7	-20.3	2038	200-SC	26.81	19.01	-13.3	-11.6
315.00 Accessory Electric Equipment	2038	200-SC	34.93	21.84	-19.6	-20.0	2038	200-SC	29.84	19.01	-11.8	-11.3
316.00 Miscellaneous Power Plant Equipment	2038	200-SC	35.89	21.84	-20.3	-20.3	2038	200-SC	30.51	19.01	-11.5	-11.6
Total Four Corners Units 4-5									27.11	19.01	-11.8	-11.7
Four Corners Common												
311.00 Structures and Improvements	2038	200-SC	26.79	21.86	-3.1	-11.2	2038	200-SC	23.89	19.02	-3.1	-8.2
312.00 Boiler Plant Equipment	2038	200-SC	30.09	21.85	-12.8	-12.1	2038	200-SC	28.59	19.01	-10.2	-9.0
314.00 Turbogenerator Units	2038	200-SC	37.20	21.84	-8.9	-11.8	2038	200-SC	32.27	19.00	-6.8	-8.7
315.00 Accessory Electric Equipment	2038	200-SC	25.92	21.86	-8.9	-11.5	2038	200-SC	23.75	19.02	-7.3	-8.5
316.00 Miscellaneous Power Plant Equipment	2038	200-SC	34.86	21.84	-11.0	-11.8	2038	200-SC	27.75	19.01	-9.8	-8.7
Total Four Corners Common									26.36	19.01	-6.6	-8.7
NUCLEAR PRODUCTION (by Unit)												
Palo Verde												
321.00 Structures and Improvements									45.35	26.75	-0.7	-0.4
322.00 Reactor Plant Equipment									46.35	25.94	-2.6	-1.0
323.00 Turbogenerator Units									42.95	26.01	-0.4	-0.3
324.00 Accessory Electric Equipment									50.24	25.98	-0.7	-0.4
325.00 Miscellaneous Power Plant Equipment									38.90	26.94	-1.3	-0.4
Total Palo Verde									45.24	26.28	-1.4	-0.6

ARIZONA PUBLIC SERVICE COMPANY
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Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Palo Verde Unit 1												
321.00 Structures and Improvements	2044	200-SC	52.70	27.41	-0.5	-0.4	2044	200-SC	50.06	24.63	-0.5	-0.3
322.00 Reactor Plant Equipment	2044	200-SC	47.42	27.43	-1.3	-1.1	2044	200-SC	46.74	24.63	-1.4	-1.0
323.00 Turbogenerator Units	2044	200-SC	45.43	27.43	-1.4	-0.4	2044	200-SC	42.19	24.64	-2.0	-0.3
324.00 Accessory Electric Equipment	2044	200-SC	52.59	27.41	-0.5	-0.4	2044	200-SC	51.10	24.62	-0.5	-0.3
325.00 Miscellaneous Power Plant Equipment	2044	200-SC	49.87	27.41	-1.3	-0.4	2044	200-SC	46.77	24.63	-1.2	-0.3
Total Palo Verde Unit 1									47.04	24.63	-1.2	-0.6
Palo Verde Unit 2												
321.00 Structures and Improvements	2045	200-SC	54.04	28.33	-0.4	-0.4	2045	200-SC	52.67	25.55	-0.5	-0.4
322.00 Reactor Plant Equipment	2045	200-SC	46.16	28.35	-2.3	-1.2	2045	200-SC	45.28	25.57	-2.2	-1.0
323.00 Turbogenerator Units	2045	200-SC	44.59	28.36	-1.1	-0.4	2045	200-SC	42.92	25.57	-1.5	-0.3
324.00 Accessory Electric Equipment	2045	200-SC	52.50	28.34	-0.6	-0.4	2045	200-SC	50.84	25.56	-0.8	-0.4
325.00 Miscellaneous Power Plant Equipment	2045	200-SC	49.51	28.34	-1.1	-0.4	2045	200-SC	48.77	25.56	-1.0	-0.3
Total Palo Verde Unit 2									46.74	25.57	-1.6	-0.7
Palo Verde Unit 3												
321.00 Structures and Improvements	2047	200-SC	53.93	30.17	-0.4	-0.4	2047	200-SC	53.18	27.41	-0.4	-0.4
322.00 Reactor Plant Equipment	2047	200-SC	47.58	30.20	-3.1	-1.2	2047	200-SC	46.77	27.43	-3.2	-1.1
323.00 Turbogenerator Units	2047	200-SC	47.49	30.19	-0.6	-0.4	2047	200-SC	44.00	27.43	1.7	-0.4
324.00 Accessory Electric Equipment	2047	200-SC	52.54	30.18	-0.7	-0.4	2047	200-SC	51.24	27.41	-0.8	-0.4
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	50.59	30.18	-1.4	-0.4	2047	200-SC	49.39	27.42	-1.3	-0.4
Total Palo Verde Unit 3									47.82	27.42	-1.4	-0.7
Palo Verde Water Reclamation												
321.00 Structures and Improvements	2047	200-SC	41.80	30.22	-1.1	-0.4	2047	200-SC	39.56	27.45	-1.0	-0.4
322.00 Reactor Plant Equipment	2047	200-SC	33.03	30.25	-1.2	-1.2	2047	200-SC	32.04	27.47	-1.1	-1.1
323.00 Turbogenerator Units	2047	200-SC	51.49	30.18	-6.4	-0.4	2047	200-SC	51.39	27.41	-6.4	-0.4
324.00 Accessory Electric Equipment												
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	40.07	30.22	-0.3	-0.4	2047	200-SC	35.63	27.46	-111.2	-0.4
Total Palo Verde Water Reclamation									39.55	27.45	-1.1	-0.4

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Palo Verde Common												
321.00 Structures and Improvements	2047	200-SC	42.59	30.21	-0.8	-0.4	2047	200-SC	40.99	27.44	-0.9	-0.4
322.00 Reactor Plant Equipment	2047	200-SC	45.74	30.20	-10.2	-1.2	2047	200-SC	44.29	27.43	-12.3	-1.1
323.00 Turbogenerator Units	2047	200-SC	35.40	30.24	-4.3	-0.4	2047	200-SC	34.21	27.46	-3.8	-0.4
324.00 Accessory Electric Equipment	2047	200-SC	44.78	30.21	-0.6	-0.4	2047	200-SC	43.28	27.44	-0.8	-0.4
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	37.74	30.23	-1.4	-0.4	2047	200-SC	34.62	27.46	-1.1	-0.4
Total Palo Verde Common									38.72	27.45	-2.0	-0.5
OTHER PRODUCTION												
Combined Cycle												
341.00 Structures and Improvements									28.02	18.39	-5.3	-5.0
342.00 Fuel Holders, Products and Accessories									25.59	14.02	-5.5	-5.0
343.00 Prime Movers									30.91	18.22	-6.6	-5.0
344.00 Generators and Devices									23.57	16.84	5.4	-5.0
345.00 Accessory Electric Equipment									22.11	14.61	-7.6	-5.0
346.00 Miscellaneous Power Plant Equipment									21.46	15.15	-5.6	-5.0
Total Combined Cycle									25.05	16.87	1.1	-5.0
Redhawk CC Units 1-2												
341.00 Structures and Improvements	2037	200-SC	30.53	20.91	-4.8	-5.0	2037	200-SC	29.85	18.06	-4.8	-5.0
342.00 Fuel Holders, Products and Accessories	2037	200-SC	25.05	20.92	-5.4	-5.0	2037	200-SC	23.95	18.07	-6.3	-5.0
343.00 Prime Movers	2037	200-SC	31.04	20.90	-8.4	-5.0	2037	200-SC	29.97	18.05	-8.5	-5.0
344.00 Generators and Devices	2037	200-SC	25.53	20.91	11.3	-5.0	2037	200-SC	23.58	18.06	9.6	-5.0
345.00 Accessory Electric Equipment	2037	200-SC	31.05	20.90	-4.2	-5.0	2037	200-SC	27.20	18.06	-9.8	-5.0
346.00 Miscellaneous Power Plant Equipment	2037	200-SC	24.57	20.92	-3.8	-5.0	2037	200-SC	24.23	18.07	-3.8	-5.0
Total Redhawk CC Units 1-2									25.17	18.06	4.0	-5.0
West Phoenix												
341.00 Structures and Improvements									27.02	18.58	-5.6	-5.0
342.00 Fuel Holders, Products and Accessories									26.39	12.05	-5.1	-5.0
343.00 Prime Movers									31.84	18.38	-4.2	-5.0
344.00 Generators and Devices									23.56	15.42	-1.3	-5.0
345.00 Accessory Electric Equipment									19.82	13.06	-6.1	-5.0
346.00 Miscellaneous Power Plant Equipment									20.31	13.94	-6.7	-5.0
Total West Phoenix									24.94	15.72	-2.9	-5.0

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
West Phoenix CC Units 1-3												
341.00 Structures and Improvements	2030	200-SC	25.02	14.23	-4.9	-5.0	2030	200-SC	23.84	11.33	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2030	200-SC	25.61	14.23	-5.2	-5.0	2030	200-SC	26.79	11.33	-5.2	-5.0
343.00 Prime Movers												
344.00 Generators and Devices	2030	200-SC	25.17	14.23	-3.4	-5.0	2030	200-SC	20.16	11.33	-4.9	-5.0
345.00 Accessory Electric Equipment	2030	200-SC	19.28	14.23	-6.9	-5.0	2030	200-SC	17.23	11.33	-6.3	-5.0
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	20.85	14.23	-4.8	-5.0	2030	200-SC	18.33	11.33	-7.4	-5.0
Total West Phoenix CC Units 1-3									20.07	11.33	-5.3	-5.0
West Phoenix CC Unit 4												
341.00 Structures and Improvements	2036	200-SC	32.59	19.96	-5.1	-5.0	2036	200-SC	25.36	17.11	-5.1	-5.0
342.00 Fuel Holders, Products and Accessories	2036	200-SC	33.73	19.96	-5.0	-5.0	2036	200-SC	32.60	17.10	-5.0	-5.0
343.00 Prime Movers	2036	200-SC	33.65	19.96	0.6	-5.0	2036	200-SC	33.48	17.10	0.6	-5.0
344.00 Generators and Devices	2036	200-SC	27.51	19.96	-4.8	-5.0	2036	200-SC	27.29	17.11	-4.8	-5.0
345.00 Accessory Electric Equipment	2036	200-SC	25.84	19.97	-5.0	-5.0	2036	200-SC	23.88	17.11	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment	2036	200-SC	22.59	19.97	-4.9	-5.0	2036	200-SC	21.46	17.11	-4.1	-5.0
Total West Phoenix CC Unit 4									30.46	17.10	-1.6	-5.0
West Phoenix CC Unit 5												
341.00 Structures and Improvements	2038	200-SC	32.33	21.85	-5.3	-5.0	2038	200-SC	30.89	19.01	-4.6	-5.0
342.00 Fuel Holders, Products and Accessories							2030	200-SC	17.95	11.33	-5.0	-5.0
343.00 Prime Movers	2038	200-SC	31.65	21.85	-6.1	-5.0	2038	200-SC	31.03	19.01	-6.4	-5.0
344.00 Generators and Devices	2038	200-SC	28.72	21.86	5.9	-5.0	2038	200-SC	26.25	19.01	1.7	-5.0
345.00 Accessory Electric Equipment	2038	200-SC	31.69	21.85	-5.3	-5.0	2038	200-SC	28.84	19.01	-5.7	-5.0
346.00 Miscellaneous Power Plant Equipment	2038	200-SC	25.22	21.86	-5.4	-5.0	2038	200-SC	24.43	19.02	-5.6	-5.0
Total West Phoenix CC Unit 5									27.67	18.91	-1.5	-5.0
West Phoenix Common												
341.00 Structures and Improvements	2038	200-SC	32.02	21.85	-7.5	-5.0	2038	200-SC	25.95	19.02	-6.3	-5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices												
345.00 Accessory Electric Equipment												
346.00 Miscellaneous Power Plant Equipment												
Total West Phoenix Common									25.95	19.02	-6.3	-5.0

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A	B	C	D	E	F	G	H	I	J	K	L	M
Combustion Turbine												
341.00 Structures and Improvements									21.51	13.86	-15.0	-5.0
342.00 Fuel Holders, Products and Accessories									33.00	14.76	-5.4	-5.0
343.00 Prime Movers									27.23	16.85	-7.1	-5.0
344.00 Generators and Devices									29.81	27.88	-5.1	-5.0
345.00 Accessory Electric Equipment									27.64	15.78	-5.6	-5.0
346.00 Miscellaneous Power Plant Equipment									24.06	16.56	-5.2	-5.0
Total Combustion Turbine									28.52	22.90	-6.1	-5.0
Douglas CT												
341.00 Structures and Improvements	2030	200-SC	22.02	14.23	-5.0	-5.0	2030	200-SC	22.09	11.33	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2030	200-SC	42.08	14.22	-6.4	-5.0	2030	200-SC	42.07	11.32	-6.4	-5.0
343.00 Prime Movers	2030	200-SC	17.14	14.24	-50.6	-5.0	2030	200-SC	17.15	11.33	-50.6	-5.0
344.00 Generators and Devices	2030	200-SC	26.54	14.23	-5.0	-5.0	2030	200-SC	26.61	11.33	-5.0	-5.0
345.00 Accessory Electric Equipment	2030	200-SC	39.59	14.22	-5.9	-5.0	2030	200-SC	23.76	11.33	-7.2	-5.0
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	42.04	14.22	-4.1	-5.0	2030	200-SC	42.09	11.32	-4.1	-5.0
Total Douglas CT									19.35	11.33	-37.0	-5.0
Ocotillo												
341.00 Structures and Improvements									15.79	11.33	-27.7	-5.0
342.00 Fuel Holders, Products and Accessories									22.36	11.33	-5.2	-5.0
343.00 Prime Movers									18.45	11.33	-13.3	-5.0
344.00 Generators and Devices									31.19	30.40	-5.1	-5.0
345.00 Accessory Electric Equipment									21.74	11.33	-5.6	-5.0
346.00 Miscellaneous Power Plant Equipment									26.73	11.33	-4.8	-5.0
Total Ocotillo									30.15	28.80	-5.5	-5.0
Ocotillo CT Units 1-2												
341.00 Structures and Improvements	2030	200-SC	18.74	14.23	-9.3	-5.0	2030	200-SC	15.79	11.33	-27.7	-5.0
342.00 Fuel Holders, Products and Accessories	2030	200-SC	29.67	14.23	-5.0	-5.0	2030	200-SC	22.36	11.33	-5.2	-5.0
343.00 Prime Movers	2030	200-SC	19.09	14.23	-14.0	-5.0	2030	200-SC	18.45	11.33	-13.3	-5.0
344.00 Generators and Devices	2030	200-SC	22.32	14.23	-5.5	-5.0	2030	200-SC	20.16	11.33	-7.4	-5.0
345.00 Accessory Electric Equipment	2030	200-SC	21.72	14.23	-5.6	-5.0	2030	200-SC	21.74	11.33	-5.6	-5.0
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	25.83	14.23	-4.8	-5.0	2030	200-SC	26.73	11.33	-4.8	-5.0
Total Octillo CT Units 1-2									19.21	11.33	-11.3	-5.0

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A	B	C	D	E	F	G	H	I	J	K	L	M
Ocotillo CT Units 3-7												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices							2051	200-SC	31.64	31.18	-5.0	-5.0
345.00 Accessory Electric Equipment												
346.00 Miscellaneous Power Plant Equipment												
Total Octillo CT Units 3-7									31.64	31.18	-5.0	-5.0
Saguaro												
341.00 Structures and Improvements									20.90	11.33	-26.0	-5.0
342.00 Fuel Holders, Products and Accessories									34.90	11.32	-5.7	-5.0
343.00 Prime Movers									17.65	11.72	-10.4	-5.0
344.00 Generators and Devices									23.87	14.27	-5.1	-5.0
345.00 Accessory Electric Equipment									21.69	11.88	-5.6	-5.0
346.00 Miscellaneous Power Plant Equipment									32.45	11.33	-4.8	-5.0
Total Saguaro									21.39	12.94	-7.9	-5.0
Saguaro CT Units 1-2												
341.00 Structures and Improvements	2030	200-SC	21.68	14.23	-8.8	-5.0	2030	200-SC	20.90	11.33	-26.0	-5.0
342.00 Fuel Holders, Products and Accessories	2030	200-SC	34.85	14.22	-5.7	-5.0	2030	200-SC	34.90	11.32	-5.7	-5.0
343.00 Prime Movers	2030	200-SC	22.10	14.23	-10.7	-5.0	2030	200-SC	17.18	11.33	-10.8	-5.0
344.00 Generators and Devices	2030	200-SC	29.85	14.23	-5.3	-5.0	2030	200-SC	16.22	11.33	-5.1	-5.0
345.00 Accessory Electric Equipment	2030	200-SC	22.02	14.23	-5.9	-5.0	2030	200-SC	21.48	11.33	-5.7	-5.0
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	33.93	14.22	-4.9	-5.0	2030	200-SC	32.45	11.33	-4.8	-5.0
Total Saguaro CT Units 1-2									17.81	11.33	-9.4	-5.0
Saguaro CT Unit 3												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2037	200-SC	25.14	20.92	-5.0	-5.0	2037	200-SC	25.18	18.06	-5.0	-5.0
344.00 Generators and Devices	2037	200-SC	33.69	20.90	-5.1	-5.0	2037	200-SC	33.73	18.05	-5.1	-5.0
345.00 Accessory Electric Equipment	2037	200-SC	33.70	20.90	-5.0	-5.0	2037	200-SC	24.03	18.07	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment												
Total Saguaro CT Unit 3									32.74	18.05	-5.1	-5.0

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A	B	C	D	E	F	G	H	I	J	K	L	M
Sundance Units 1-10												
341.00 Structures and Improvements	2037	200-SC	29.70	20.91	-6.8	-5.0	2037	200-SC	28.79	18.06	-6.9	-5.0
342.00 Fuel Holders, Products and Accessories	2037	200-SC	29.93	20.91	-5.0	-5.0	2037	200-SC	29.69	18.06	-5.2	-5.0
343.00 Prime Movers	2037	200-SC	30.53	20.91	-5.0	-5.0	2037	200-SC	30.06	18.06	-5.1	-5.0
344.00 Generators and Devices	2037	200-SC	21.85	20.92	-5.0	-5.0	2037	200-SC	21.70	18.07	-5.0	-5.0
345.00 Accessory Electric Equipment	2037	200-SC	30.16	20.91	-5.2	-5.0	2037	200-SC	29.56	18.06	-5.3	-5.0
346.00 Miscellaneous Power Plant Equipment	2037	200-SC	27.86	20.91	-5.0	-5.0	2037	200-SC	21.27	18.07	-5.0	-5.0
Total Sun Dance Units 1-10									29.16	18.06	-5.2	-5.0
West Phoenix CT Units 1-2												
341.00 Structures and Improvements	2030	200-SC	16.66	14.24	-7.7	-5.0	2030	200-SC	16.36	11.33	-7.6	-5.0
342.00 Fuel Holders, Products and Accessories	2030	200-SC	31.39	14.22	-5.0	-5.0	2030	200-SC	30.97	11.33	-6.5	-5.0
343.00 Prime Movers	2030	200-SC	20.27	14.23	-10.0	-5.0	2030	200-SC	20.55	11.33	-10.2	-5.0
344.00 Generators and Devices	2030	200-SC	21.33	14.23	-6.3	-5.0	2030	200-SC	17.28	11.33	-6.0	-5.0
345.00 Accessory Electric Equipment	2030	200-SC	41.82	14.22	-5.1	-5.0	2030	200-SC	28.63	11.33	-3.8	-5.0
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	29.86	14.23	-7.8	-5.0	2030	200-SC	29.90	11.33	-7.8	-5.0
Total West Phoenix CT Units 1-2									19.41	11.33	-8.2	-5.0
Yucca												
341.00 Structures and Improvements									18.98	12.55	-25.8	-5.0
342.00 Fuel Holders, Products and Accessories									42.38	15.65	-5.1	-5.0
343.00 Prime Movers									31.75	21.37	-6.5	-5.0
344.00 Generators and Devices									25.89	11.52	-6.9	-5.0
345.00 Accessory Electric Equipment									29.64	13.60	-7.9	-5.0
346.00 Miscellaneous Power Plant Equipment									27.99	16.80	-5.0	-5.0
Total Yucca									30.08	18.84	-7.7	-5.0
Yucca CT Units 1-4												
341.00 Structures and Improvements	2030	200-SC	19.06	14.23	-6.1	-5.0	2030	200-SC	17.72	11.33	-29.5	-5.0
342.00 Fuel Holders, Products and Accessories	2030	200-SC	46.94	14.21	-5.1	-5.0	2030	200-SC	47.16	11.32	-5.1	-5.0
343.00 Prime Movers	2030	200-SC	30.01	14.23	-12.9	-5.0	2030	200-SC	25.97	11.33	-12.3	-5.0
344.00 Generators and Devices	2030	200-SC	26.18	14.23	-6.0	-5.0	2030	200-SC	25.83	11.33	-6.9	-5.0
345.00 Accessory Electric Equipment	2030	200-SC	29.68	14.23	-8.2	-5.0	2030	200-SC	29.75	11.33	-8.2	-5.0
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	33.71	14.22	-5.0	-5.0	2030	200-SC	29.27	11.33	-5.0	-5.0
Total Yucca CT Units 1-4									25.77	11.33	-12.1	-5.0

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A	B	C	D	E	F	G	H	I	J	K	L	M
Yucca CT Units 5-6												
341.00 Structures and Improvements	2043	200-SC	30.49	26.54	-5.0	-5.0	2043	200-SC	30.53	23.74	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2043	200-SC	33.48	26.54	-5.0	-5.0	2043	200-SC	33.47	23.73	-5.0	-5.0
343.00 Prime Movers	2043	200-SC	33.54	26.54	-5.0	-5.0	2043	200-SC	33.11	23.73	-5.4	-5.0
344.00 Generators and Devices	2043	200-SC	32.00	26.54	-5.0	-5.0	2043	200-SC	29.72	23.74	-5.0	-5.0
345.00 Accessory Electric Equipment	2043	200-SC	29.39	26.55	-6.6	-5.0	2043	200-SC	29.14	23.74	-6.6	-5.0
346.00 Miscellaneous Power Plant Equipment	2043	200-SC	27.02	26.55	-5.0	-5.0	2043	200-SC	26.36	23.74	-5.0	-5.0
Total Yucca CT Units 5-6									32.89	23.73	-5.4	-5.0
Solar Units												
341.00 Structures and Improvements									28.94	23.89	-9.3	-9.3
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices									28.64	23.56	-8.8	-9.7
345.00 Accessory Electric Equipment									28.54	23.34	-9.5	-9.5
346.00 Miscellaneous Power Plant Equipment									29.01	23.89	-9.2	-9.2
Total Solar Units									28.64	23.54	-8.9	-9.6
Chino Valley												
341.05 Structures and Improvements	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-7.4
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-7.4
345.05 Accessory Electric Equipment	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-7.4
346.05 Miscellaneous Power Plant Equipment	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-7.4
Total Chino Valley									28.93	22.80	-7.4	-7.4
Cotton Center												
341.05 Structures and Improvements	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.95	21.86	-6.8	-6.8
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.75	21.86	-5.0	-6.8
345.05 Accessory Electric Equipment	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.95	21.86	-6.8	-6.8
346.05 Miscellaneous Power Plant Equipment	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.95	21.86	-6.8	-6.8
Total Cotton Center									28.79	21.86	-5.4	-6.8

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A	B	C	D	E	F	G	H	I	J	K	L	M
Desert Star												
341.05 Structures and Improvements	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.89	25.61	-10.9	-10.9
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.31	25.62	1.8	-10.9
345.05 Accessory Electric Equipment	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.89	25.61	-10.9	-10.9
346.05 Miscellaneous Power Plant Equipment	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.89	25.61	-10.9	-10.9
Total Desert Star									28.41	25.62	-0.3	-10.9
Foothills Units												
341.05 Structures and Improvements	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-8.5
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-8.5
345.05 Accessory Electric Equipment	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-8.5
346.05 Miscellaneous Power Plant Equipment	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-8.5
Total Foothills Units									28.91	23.74	-8.5	-8.5
Gila Bend												
341.05 Structures and Improvements	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-10.3
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-10.3
345.05 Accessory Electric Equipment	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-10.3
346.05 Miscellaneous Power Plant Equipment	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-10.3
Total Gila Bend									28.90	24.68	-10.3	-10.3
Hyder												
341.05 Structures and Improvements	2042	200-SC	28.74	25.62	-4.4	-4.4	2042	200-SC	28.78	22.80	-4.4	-4.4
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2042	200-SC	28.84	25.61	-4.4	-4.4	2042	200-SC	28.88	22.80	-4.4	-4.4
345.05 Accessory Electric Equipment	2042	200-SC	29.00	25.61	-4.4	-4.4	2042	200-SC	29.04	22.80	-4.4	-4.4
346.05 Miscellaneous Power Plant Equipment	2042	200-SC	29.58	25.61	-4.4	-4.4	2042	200-SC	29.63	22.80	-4.4	-4.4
Total Hyder									28.90	22.80	-4.4	-4.4

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A	B	C	D	E	F	G	H	I	J	K	L	M
Legacy												
341.00 Structures and Improvements	2037	200-SC	41.95	20.89	-3.9	-5.0	2037	200-SC	40.13	18.05	-0.7	-0.2
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices	2037	200-SC	25.92	20.91	-3.3	-5.0	2037	200-SC	24.94	18.06	-1.0	-0.2
345.00 Accessory Electric Equipment	2037	200-SC	22.73	20.92	-5.2	-5.0	2037	200-SC	22.99	18.07	-1.8	-0.2
346.00 Miscellaneous Power Plant Equipment												
Total Legacy									24.84	18.06	-1.1	-0.2
Luke AFB												
341.05 Structures and Improvements	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-13.0
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-13.0
345.05 Accessory Electric Equipment	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-13.0
346.05 Miscellaneous Power Plant Equipment	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-13.0
Total Luke AFB									28.89	25.61	-13.0	-13.0
Paloma												
341.05 Structures and Improvements	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.95	21.86	-8.5	-8.5
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.91	21.86	-8.5	-8.5
345.05 Accessory Electric Equipment	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.95	21.86	-8.5	-8.5
346.05 Miscellaneous Power Plant Equipment	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.95	21.86	-8.5	-8.5
Total Paloma									28.92	21.86	-8.5	-8.5
Red Rock												
341.05 Structures and Improvements	30	SQ					2046	200-SC	28.88	26.55	-15.5	-15.5
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30	SQ					2046	200-SC	28.88	26.55	-15.5	-15.5
345.05 Accessory Electric Equipment	30	SQ					2046	200-SC	28.88	26.55	-15.5	-15.5
346.05 Miscellaneous Power Plant Equipment							2046	200-SC	28.88	26.55	-15.5	-15.5
Total Redrock									28.88	26.55	-15.5	-15.5

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2018) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Roof Tops												
341.05 Structures and Improvements	2042	200-SC	28.71	25.62	-5.0	-5.0	2042	200-SC	28.73	22.80	-16.8	-16.8
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2042	200-SC	28.58	25.62	-5.0	-5.0	2042	200-SC	27.52	22.80	-16.9	-16.9
345.05 Accessory Electric Equipment	2042	200-SC	28.62	25.62	-5.0	-5.0	2042	200-SC	26.90	22.80	-17.0	-16.9
346.05 Miscellaneous Power Plant Equipment												
Total Roof Tops									27.42	22.80	-17.0	-16.9

Statements A through E

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Accrual Rates - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Statement A

Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D=B+C	E	F	G=E+F	H=G-D
STEAM PRODUCTION							
311.00 Structures and Improvements	5.01%	0.39%	5.40%	5.84%	0.32%	6.16%	0.76%
312.00 Boiler Plant Equipment	2.90%	0.33%	3.23%	4.37%	0.38%	4.75%	1.52%
314.00 Turbogenerator Units	3.63%	0.36%	3.99%	4.85%	0.37%	5.22%	1.23%
315.00 Accessory Electric Equipment	4.26%	0.41%	4.67%	4.93%	0.32%	5.25%	0.58%
316.00 Miscellaneous Power Plant Equipment	3.80%	0.43%	4.23%	4.55%	0.35%	4.90%	0.67%
Total Steam Production Plant	3.24%	0.35%	3.59%	4.56%	0.37%	4.93%	1.34%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	0.98%	0.01%	0.99%	1.22%	0.01%	1.23%	0.24%
322.00 Reactor Plant Equipment	0.76%	0.06%	0.82%	0.75%	0.04%	0.79%	-0.03%
323.00 Turbogenerator Units	0.89%	0.03%	0.92%	1.08%	0.01%	1.09%	0.17%
324.00 Accessory Electric Equipment	0.39%	0.01%	0.40%	0.48%	0.01%	0.49%	0.09%
325.00 Miscellaneous Power Plant Equipment	1.39%	0.05%	1.44%	1.74%	0.01%	1.75%	0.31%
Total Nuclear Production Plant	0.86%	0.04%	0.90%	0.98%	0.02%	1.00%	0.10%
OTHER PRODUCTION							
341.00 Structures and Improvements	3.53%	0.25%	3.78%	3.82%	0.19%	4.01%	0.23%
342.00 Fuel Holders, Products and Accessories	3.60%	0.18%	3.78%	3.90%	0.18%	4.08%	0.30%
343.00 Prime Movers	3.29%	0.15%	3.44%	3.49%	0.16%	3.65%	0.21%
344.00 Generators and Devices	3.70%	0.07%	3.77%	3.81%	0.19%	4.00%	0.23%
345.00 Accessory Electric Equipment	3.74%	0.23%	3.97%	3.89%	0.23%	4.12%	0.15%
346.00 Miscellaneous Power Plant Equipment	3.95%	0.20%	4.15%	4.60%	0.20%	4.80%	0.65%
Total Other Production Plant	3.62%	0.11%	3.73%	3.76%	0.19%	3.95%	0.22%
TRANSMISSION PLANT							
352.02 Structures and Improvements	2.51%		2.51%	2.48%		2.48%	-0.03%
353.00 Station Equipment	1.91%	0.09%	2.00%	1.90%	0.07%	1.97%	-0.03%
354.00 Towers and Fixtures	1.78%		1.78%	1.77%		1.77%	-0.01%
355.00 Poles and Fixtures	1.85%	0.37%	2.22%	1.85%	0.26%	2.11%	-0.11%
356.00 Overhead Conductors and Devices	1.74%	0.33%	2.07%	1.75%	0.25%	2.00%	-0.07%
Total Transmission Plant	1.91%	0.10%	2.01%	1.90%	0.07%	1.97%	-0.04%
DISTRIBUTION PLANT							
361.00 Structures and Improvements	1.58%	0.08%	1.66%	1.59%	0.10%	1.69%	0.03%
362.00 Station Equipment	2.20%	0.08%	2.28%	2.14%	0.10%	2.24%	-0.04%
363.00 Storage Battery Equipment	8.79%		8.79%	9.76%		9.76%	0.97%
364.01 Poles, Towers and Fixtures - Wood	2.10%	0.19%	2.29%	2.12%	0.37%	2.49%	0.20%
364.02 Poles, Towers and Fixtures - Steel	1.95%	0.19%	2.14%	1.95%	0.15%	2.10%	-0.04%
365.00 Overhead Conductors and Devices	1.92%	0.20%	2.12%	1.94%	0.31%	2.25%	0.13%
366.00 Underground Conduit	1.57%	0.17%	1.74%	1.58%	0.20%	1.78%	0.04%
367.00 Underground Conductors and Devices	2.34%	0.20%	2.54%	2.36%	0.32%	2.68%	0.14%
368.00 Line Transformers	1.70%	0.06%	1.76%	1.73%	0.08%	1.81%	0.05%
369.00 Services	1.68%	0.33%	2.01%	1.70%	0.29%	1.99%	-0.02%
370.01 Meters - Electronic	5.52%	-0.03%	5.49%	5.93%		5.93%	0.44%
370.03 Meters - AMI	4.84%		4.84%	6.10%		6.10%	1.26%
371.00 Installations on Customers' Premises	2.11%	0.31%	2.42%	2.12%	0.28%	2.40%	-0.02%
373.00 Street Lighting and Signal Systems	1.72%	0.18%	1.90%	1.74%	0.22%	1.96%	0.06%
Total Distribution Plant	2.15%	0.16%	2.31%	2.23%	0.22%	2.45%	0.14%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	2.52%	0.17%	2.69%	2.51%	0.21%	2.72%	0.03%
391.CM Office Furn. and Equip. - Computer	12.86%	0.02%	12.88%	12.23%		12.23%	-0.65%
397.00 Communication Equipment	4.83%		4.83%	4.74%		4.74%	-0.09%
Total Depreciable	6.50%	0.06%	6.56%	6.27%	0.07%	6.34%	-0.22%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Depreciation Accrual Rates - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	Current			SFAS 143 Method			Difference
	Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D=B+C	E	F	G=E+F	H=G-D
Amortizable							
391.FE Office Furn. and Equip. - Furniture	4.98%		4.98%	← 20 Year Amortization →		4.98%	
393.00 Stores Equipment	5.00%		5.00%	← 20 Year Amortization →		5.00%	
394.00 Tools, Shop and Garage Equipment	4.98%		4.98%	← 20 Year Amortization →		4.98%	
395.00 Laboratory Equipment	5.00%		5.00%	← 20 Year Amortization →		5.00%	
398.00 Miscellaneous Equipment	4.17%		4.17%	← 24 Year Amortization →		4.17%	
Total Amortizable	4.84%		4.84%	4.84%		4.84%	
Total General Plant	6.26%	0.05%	6.31%	6.07%	0.06%	6.13%	-0.18%
TOTAL UTILITY	2.60%	0.14%	2.74%	2.84%	0.18%	3.02%	0.28%
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	7.05%	0.50%	7.55%	8.32%	0.35%	8.67%	1.12%
312.00 Boiler Plant Equipment	7.01%	0.58%	7.59%	8.14%	0.40%	8.54%	0.95%
314.00 Turbogenerator Units	6.63%	0.45%	7.08%	7.55%	0.38%	7.93%	0.85%
315.00 Accessory Electric Equipment	6.12%	0.44%	6.56%	7.16%	0.31%	7.47%	0.91%
316.00 Miscellaneous Power Plant Equipment	7.29%	0.55%	7.84%	8.69%	0.42%	9.11%	1.27%
Total Cholla	6.90%	0.54%	7.44%	8.02%	0.39%	8.41%	0.97%
Cholla Unit 1							
311.00 Structures and Improvements	5.36%	0.44%	5.80%	5.96%	0.36%	6.32%	0.52%
312.00 Boiler Plant Equipment	6.04%	0.65%	6.69%	6.83%	0.45%	7.28%	0.59%
314.00 Turbogenerator Units	6.37%	0.58%	6.95%	7.01%	0.46%	7.47%	0.52%
315.00 Accessory Electric Equipment	5.48%	0.48%	5.96%	6.09%	0.38%	6.47%	0.51%
316.00 Miscellaneous Power Plant Equipment	5.15%	0.45%	5.60%	6.89%	0.44%	7.33%	1.73%
Total Cholla Unit 1	6.02%	0.61%	6.63%	6.78%	0.44%	7.22%	0.59%
Cholla Unit 3							
311.00 Structures and Improvements	7.02%	0.46%	7.48%	8.08%	0.33%	8.41%	0.93%
312.00 Boiler Plant Equipment	7.28%	0.55%	7.83%	8.48%	0.39%	8.87%	1.04%
314.00 Turbogenerator Units	6.72%	0.39%	7.11%	7.79%	0.34%	8.13%	1.02%
315.00 Accessory Electric Equipment	5.99%	0.42%	6.41%	6.95%	0.27%	7.22%	0.81%
316.00 Miscellaneous Power Plant Equipment	7.24%	0.52%	7.76%	8.51%	0.38%	8.89%	1.13%
Total Cholla Unit 3	7.05%	0.51%	7.56%	8.20%	0.37%	8.57%	1.01%
Cholla Common							
311.00 Structures and Improvements	7.19%	0.52%	7.71%	8.56%	0.36%	8.92%	1.21%
312.00 Boiler Plant Equipment	7.27%	0.60%	7.87%	8.55%	0.38%	8.93%	1.06%
314.00 Turbogenerator Units	8.50%	0.63%	9.13%	8.52%	0.37%	8.89%	-0.24%
315.00 Accessory Electric Equipment	7.29%	0.47%	7.76%	9.13%	0.42%	9.55%	1.79%
316.00 Miscellaneous Power Plant Equipment	7.89%	0.59%	8.48%	9.27%	0.44%	9.71%	1.23%
Total Cholla Common	7.31%	0.56%	7.87%	8.66%	0.38%	9.04%	1.17%
Four Corners							
311.00 Structures and Improvements	2.52%	0.25%	2.77%	2.80%	0.28%	3.08%	0.31%
312.00 Boiler Plant Equipment	1.47%	0.25%	1.72%	3.06%	0.37%	3.43%	1.71%
314.00 Turbogenerator Units	1.59%	0.30%	1.89%	3.02%	0.37%	3.39%	1.50%
315.00 Accessory Electric Equipment	2.72%	0.39%	3.11%	3.09%	0.32%	3.41%	0.30%
316.00 Miscellaneous Power Plant Equipment	2.36%	0.38%	2.74%	2.84%	0.32%	3.16%	0.42%
Total Four Corners	1.62%	0.26%	1.88%	3.03%	0.36%	3.39%	1.51%
Four Corners Units 4-5							
311.00 Structures and Improvements	1.75%	0.31%	2.06%	1.88%	0.28%	2.16%	0.10%
312.00 Boiler Plant Equipment	1.40%	0.24%	1.64%	3.03%	0.37%	3.40%	1.76%
314.00 Turbogenerator Units	1.55%	0.30%	1.85%	3.01%	0.37%	3.38%	1.53%
315.00 Accessory Electric Equipment	2.12%	0.41%	2.53%	2.46%	0.33%	2.79%	0.26%
316.00 Miscellaneous Power Plant Equipment	2.02%	0.40%	2.42%	2.35%	0.34%	2.69%	0.27%
Total Four Corners Units 4-5	1.47%	0.26%	1.73%	2.95%	0.37%	3.32%	1.59%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Accrual Rates - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Statement A

Account Description	Current			SFAS 143 Method			Difference
	Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D=B+C	E	F	G=E+F	H=G-D
Four Corners Common							
311.00 Structures and Improvements	3.81%	0.16%	3.97%	4.33%	0.28%	4.61%	0.64%
312.00 Boiler Plant Equipment	3.44%	0.44%	3.88%	3.73%	0.27%	4.00%	0.12%
314.00 Turbogenerator Units	2.87%	0.27%	3.14%	3.39%	0.24%	3.63%	0.49%
315.00 Accessory Electric Equipment	3.93%	0.36%	4.29%	4.35%	0.30%	4.65%	0.36%
316.00 Miscellaneous Power Plant Equipment	3.03%	0.34%	3.37%	3.83%	0.28%	4.11%	0.74%
Total Four Corners Common	3.52%	0.34%	3.86%	3.99%	0.28%	4.27%	0.41%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	0.98%	0.01%	1.00%	1.22%	0.01%	1.23%	0.23%
322.00 Reactor Plant Equipment	0.76%	0.06%	0.83%	0.75%	0.04%	0.79%	-0.04%
323.00 Turbogenerator Units	0.89%	0.03%	0.92%	1.08%	0.01%	1.09%	0.17%
324.00 Accessory Electric Equipment	0.39%	0.01%	0.39%	0.48%	0.01%	0.49%	0.10%
325.00 Miscellaneous Power Plant Equipment	1.39%	0.05%	1.44%	1.74%	0.01%	1.75%	0.31%
Total Palo Verde	0.86%	0.04%	0.90%	0.98%	0.02%	1.00%	0.10%
Palo Verde Unit 1							
321.00 Structures and Improvements	0.18%		0.18%	0.35%	0.01%	0.36%	0.18%
322.00 Reactor Plant Equipment	0.60%	0.01%	0.61%	0.59%	0.03%	0.62%	0.01%
323.00 Turbogenerator Units	0.79%	0.05%	0.84%	1.02%	0.01%	1.03%	0.19%
324.00 Accessory Electric Equipment	0.19%		0.19%	0.27%	0.01%	0.28%	0.09%
325.00 Miscellaneous Power Plant Equipment	0.40%	0.04%	0.44%	0.60%	0.01%	0.61%	0.17%
Total Palo Verde Unit 1	0.49%	0.01%	0.50%	0.57%	0.02%	0.59%	0.09%
Palo Verde Unit 2							
321.00 Structures and Improvements	0.37%		0.37%	0.40%	0.01%	0.41%	0.04%
322.00 Reactor Plant Equipment	0.96%	0.06%	1.02%	0.93%	0.04%	0.97%	-0.05%
323.00 Turbogenerator Units	1.11%	0.03%	1.14%	1.16%	0.01%	1.17%	0.03%
324.00 Accessory Electric Equipment	0.47%	0.01%	0.48%	0.52%	0.01%	0.53%	0.05%
325.00 Miscellaneous Power Plant Equipment	0.69%	0.03%	0.72%	0.67%	0.01%	0.68%	-0.04%
Total Palo Verde Unit 2	0.81%	0.04%	0.85%	0.82%	0.02%	0.84%	-0.01%
Palo Verde Unit 3							
321.00 Structures and Improvements	0.29%		0.29%	0.28%	0.01%	0.29%	
322.00 Reactor Plant Equipment	0.81%	0.09%	0.90%	0.76%	0.04%	0.80%	-0.10%
323.00 Turbogenerator Units	0.81%	0.01%	0.82%	1.03%	0.01%	1.04%	0.22%
324.00 Accessory Electric Equipment	0.39%	0.01%	0.40%	0.42%	0.01%	0.43%	0.03%
325.00 Miscellaneous Power Plant Equipment	0.55%	0.04%	0.59%	0.56%	0.01%	0.57%	-0.02%
Total Palo Verde Unit 3	0.66%	0.05%	0.71%	0.68%	0.02%	0.70%	-0.01%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	2.05%	0.03%	2.08%	2.41%	0.01%	2.42%	0.34%
322.00 Reactor Plant Equipment	2.92%	0.04%	2.96%	3.06%	0.04%	3.10%	0.14%
323.00 Turbogenerator Units	1.43%	0.17%	1.60%	1.75%	0.01%	1.76%	0.16%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	2.19%	0.01%	2.20%	2.72%	0.01%	2.73%	0.53%
Total Palo Verde Water Reclamation	2.05%	0.03%	2.08%	2.41%	0.01%	2.42%	0.34%
Palo Verde Common							
321.00 Structures and Improvements	1.31%	0.02%	1.33%	1.76%	0.01%	1.77%	0.44%
322.00 Reactor Plant Equipment	0.98%	0.42%	1.40%	1.47%	0.04%	1.51%	0.11%
323.00 Turbogenerator Units	2.31%	0.24%	2.55%	2.52%	0.01%	2.53%	-0.02%
324.00 Accessory Electric Equipment	1.08%	0.01%	1.09%	1.56%	0.01%	1.57%	0.48%
325.00 Miscellaneous Power Plant Equipment	1.94%	0.06%	2.00%	2.47%	0.01%	2.48%	0.48%
Total Palo Verde Common	1.50%	0.07%	1.57%	1.99%	0.01%	2.00%	0.43%

ARIZONA PUBLIC SERVICE COMPANY Statement A
Depreciation Accrual Rates - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D=B+C	E	F	G=E+F	H=G-D
OTHER PRODUCTION							
Combined Cycle							
341.00 Structures and Improvements	4.00%	0.20%	4.20%	3.64%	0.15%	3.79%	-0.41%
342.00 Fuel Holders, Products and Accessories	4.37%	0.23%	4.60%	4.04%	0.19%	4.23%	-0.37%
343.00 Prime Movers	3.97%	0.26%	4.23%	3.60%	0.14%	3.74%	-0.49%
344.00 Generators and Devices	4.33%	-0.11%	4.22%	4.45%	0.18%	4.63%	0.41%
345.00 Accessory Electric Equipment	3.97%	0.19%	4.16%	4.73%	0.20%	4.93%	0.77%
346.00 Miscellaneous Power Plant Equipment	4.41%	0.20%	4.61%	4.81%	0.21%	5.02%	0.41%
Total Combined Cycle	3.99%	0.05%	4.04%	4.23%	0.17%	4.40%	0.36%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	4.00%	0.20%	4.20%	3.78%	0.15%	3.93%	-0.27%
342.00 Fuel Holders, Products and Accessories	4.37%	0.23%	4.60%	4.44%	0.18%	4.62%	0.02%
343.00 Prime Movers	3.97%	0.26%	4.23%	3.77%	0.15%	3.92%	-0.31%
344.00 Generators and Devices	4.33%	-0.11%	4.22%	4.50%	0.18%	4.68%	0.46%
345.00 Accessory Electric Equipment	3.97%	0.19%	4.16%	4.04%	0.16%	4.20%	0.04%
346.00 Miscellaneous Power Plant Equipment	4.41%	0.20%	4.61%	4.41%	0.18%	4.59%	-0.02%
Total Redhawk CC Units 1-2	4.22%	0.01%	4.23%	4.28%	0.17%	4.45%	0.22%
West Phoenix							
341.00 Structures and Improvements	2.90%	0.21%	3.11%	3.56%	0.16%	3.72%	0.61%
342.00 Fuel Holders, Products and Accessories	3.76%	0.19%	3.95%	3.87%	0.19%	4.06%	0.11%
343.00 Prime Movers	3.42%	0.14%	3.56%	3.44%	0.14%	3.58%	0.02%
344.00 Generators and Devices	3.86%	0.02%	3.88%	4.40%	0.19%	4.59%	0.71%
345.00 Accessory Electric Equipment	4.66%	0.30%	4.96%	5.15%	0.23%	5.38%	0.42%
346.00 Miscellaneous Power Plant Equipment	4.55%	0.23%	4.78%	5.01%	0.22%	5.23%	0.45%
Total West Phoenix	3.77%	0.09%	3.86%	4.17%	0.18%	4.35%	0.49%
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	4.03%	0.19%	4.22%	4.20%	0.20%	4.40%	0.18%
342.00 Fuel Holders, Products and Accessories	3.94%	0.20%	4.14%	3.74%	0.19%	3.93%	-0.21%
343.00 Prime Movers							
344.00 Generators and Devices	4.00%	0.14%	4.14%	4.96%	0.23%	5.19%	1.05%
345.00 Accessory Electric Equipment	5.21%	0.35%	5.56%	5.80%	0.27%	6.07%	0.51%
346.00 Miscellaneous Power Plant Equipment	4.82%	0.23%	5.05%	5.46%	0.25%	5.71%	0.66%
Total West Phoenix CC Units 1-3	4.23%	0.19%	4.42%	4.98%	0.23%	5.21%	0.79%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	3.30%	0.17%	3.47%	4.04%	0.17%	4.21%	0.74%
342.00 Fuel Holders, Products and Accessories	3.21%	0.16%	3.37%	3.21%	0.14%	3.35%	-0.02%
343.00 Prime Movers	3.21%	0.02%	3.23%	3.14%	0.14%	3.28%	0.05%
344.00 Generators and Devices	3.80%	0.18%	3.98%	3.78%	0.16%	3.94%	-0.04%
345.00 Accessory Electric Equipment	4.00%	0.20%	4.20%	4.27%	0.18%	4.45%	0.25%
346.00 Miscellaneous Power Plant Equipment	4.50%	0.22%	4.72%	4.72%	0.20%	4.92%	0.20%
Total West Phoenix CC Unit 4	3.40%	0.09%	3.49%	3.42%	0.15%	3.57%	0.08%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	3.48%	0.18%	3.66%	3.62%	0.14%	3.76%	0.10%
342.00 Fuel Holders, Products and Accessories	3.21%	0.16%	3.37%	6.18%	0.26%	6.44%	3.07%
343.00 Prime Movers	3.53%	0.20%	3.73%	3.60%	0.14%	3.74%	0.01%
344.00 Generators and Devices	3.76%	-0.09%	3.67%	4.08%	0.16%	4.24%	0.57%
345.00 Accessory Electric Equipment	3.52%	0.19%	3.71%	3.80%	0.15%	3.95%	0.24%
346.00 Miscellaneous Power Plant Equipment	4.12%	0.22%	4.34%	4.31%	0.17%	4.48%	0.14%
Total West Phoenix CC Unit 5	3.67%	0.03%	3.70%	3.93%	0.15%	4.08%	0.38%

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Statement A

Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D=B+C	E	F	G=E+F	H=G-D
West Phoenix Common							
341.00 Structures and Improvements	2.44%	0.24%	2.68%	3.35%	0.16%	3.51%	0.83%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices							
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total West Phoenix Common	2.44%	0.24%	2.68%	3.35%	0.16%	3.51%	0.83%
Combustion Turbine							
341.00 Structures and Improvements	3.98%	0.32%	4.30%	4.65%	0.21%	4.86%	0.56%
342.00 Fuel Holders, Products and Accessories	2.64%	0.14%	2.78%	3.49%	0.15%	3.64%	0.86%
343.00 Prime Movers	3.01%	0.12%	3.13%	3.42%	0.16%	3.58%	0.45%
344.00 Generators and Devices	3.41%	0.03%	3.44%	3.43%	0.12%	3.55%	0.11%
345.00 Accessory Electric Equipment	3.14%	0.18%	3.32%	3.45%	0.16%	3.61%	0.29%
346.00 Miscellaneous Power Plant Equipment	3.04%	0.16%	3.20%	4.40%	0.18%	4.58%	1.38%
Total Combustion Turbine	3.27%	0.08%	3.35%	3.47%	0.14%	3.61%	0.26%
Douglas CT							
341.00 Structures and Improvements	16.13%	0.81%	16.94%	9.15%	0.22%	9.37%	-7.57%
342.00 Fuel Holders, Products and Accessories	24.09%	1.08%	25.17%	9.30%	0.14%	9.44%	-15.73%
343.00 Prime Movers	11.37%	-9.17%	2.20%	9.05%	0.27%	9.32%	7.12%
344.00 Generators and Devices	18.97%	0.95%	19.92%	9.19%	0.18%	9.37%	-10.55%
345.00 Accessory Electric Equipment	23.54%	1.09%	24.63%	9.16%	0.19%	9.35%	-15.28%
346.00 Miscellaneous Power Plant Equipment	24.08%	1.28%	25.36%	9.30%	0.14%	9.44%	-15.92%
Total Douglas CT	14.46%	-5.82%	8.64%	9.10%	0.24%	9.34%	0.70%
Ocotillo							
341.00 Structures and Improvements	5.50%	0.48%	5.98%	7.13%	0.29%	7.42%	1.44%
342.00 Fuel Holders, Products and Accessories	3.72%	0.19%	3.91%	5.85%	0.21%	6.06%	2.15%
343.00 Prime Movers	5.41%	0.70%	6.11%	6.50%	0.25%	6.75%	0.64%
344.00 Generators and Devices	3.37%	0.01%	3.38%	3.27%	0.11%	3.38%	
345.00 Accessory Electric Equipment	4.84%	0.27%	5.11%	5.94%	0.21%	6.15%	1.04%
346.00 Miscellaneous Power Plant Equipment	4.18%	0.20%	4.38%	5.35%	0.18%	5.53%	1.15%
Total Ocotillo	3.46%	0.04%	3.50%	3.43%	0.12%	3.55%	0.05%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	5.50%	0.48%	5.98%	7.13%	0.29%	7.42%	1.44%
342.00 Fuel Holders, Products and Accessories	3.72%	0.19%	3.91%	5.85%	0.21%	6.06%	2.15%
343.00 Prime Movers	5.41%	0.70%	6.11%	6.50%	0.25%	6.75%	0.64%
344.00 Generators and Devices	4.73%	0.25%	4.98%	6.19%	0.23%	6.42%	1.44%
345.00 Accessory Electric Equipment	4.84%	0.27%	5.11%	5.94%	0.21%	6.15%	1.04%
346.00 Miscellaneous Power Plant Equipment	4.18%	0.20%	4.38%	5.35%	0.18%	5.53%	1.15%
Total Ocotillo CT Units 1-2	5.08%	0.48%	5.56%	6.36%	0.24%	6.60%	1.04%
Ocotillo CT Units 3-7							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	3.33%		3.33%	3.19%	0.11%	3.30%	-0.03%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total Ocotillo CT Units 3-7	3.33%		3.33%	3.19%	0.11%	3.30%	-0.03%

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Statement A

Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D=B+C	E	F	G=E+F	H=G-D
Saguaro							
341.00 Structures and Improvements	4.20%	0.41%	4.61%	5.39%	0.22%	5.61%	1.00%
342.00 Fuel Holders, Products and Accessories	2.16%	0.13%	2.29%	3.76%	0.15%	3.91%	1.62%
343.00 Prime Movers	4.09%	0.48%	4.57%	6.06%	0.25%	6.31%	1.74%
344.00 Generators and Devices	2.90%	0.15%	3.05%	4.11%	0.19%	4.30%	1.25%
345.00 Accessory Electric Equipment	4.02%	0.24%	4.26%	5.16%	0.21%	5.37%	1.11%
346.00 Miscellaneous Power Plant Equipment	2.25%	0.11%	2.36%	3.95%	0.16%	4.11%	1.75%
Total Saguaro	3.38%	0.27%	3.65%	4.85%	0.21%	5.06%	1.41%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	4.20%	0.41%	4.61%	5.39%	0.22%	5.61%	1.00%
342.00 Fuel Holders, Products and Accessories	2.16%	0.13%	2.29%	3.76%	0.15%	3.91%	1.62%
343.00 Prime Movers	4.10%	0.50%	4.60%	6.27%	0.26%	6.53%	1.93%
344.00 Generators and Devices	2.72%	0.15%	2.87%	6.57%	0.28%	6.85%	3.98%
345.00 Accessory Electric Equipment	4.12%	0.25%	4.37%	5.28%	0.21%	5.49%	1.12%
346.00 Miscellaneous Power Plant Equipment	2.25%	0.11%	2.36%	3.95%	0.16%	4.11%	1.75%
Total Saguaro CT Units 1-2	3.55%	0.34%	3.89%	6.10%	0.25%	6.35%	2.46%
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	3.99%	0.20%	4.19%	3.74%	0.18%	3.92%	-0.27%
344.00 Generators and Devices	3.01%	0.15%	3.16%	2.59%	0.14%	2.73%	-0.43%
345.00 Accessory Electric Equipment	3.00%	0.16%	3.16%	3.96%	0.18%	4.14%	0.98%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	3.08%	0.15%	3.23%	2.69%	0.14%	2.83%	-0.40%
Sundance Units 1-10							
341.00 Structures and Improvements	2.49%	0.23%	2.72%	2.72%	0.16%	2.88%	0.16%
342.00 Fuel Holders, Products and Accessories	2.45%	0.12%	2.57%	2.58%	0.15%	2.73%	0.16%
343.00 Prime Movers	2.34%	0.12%	2.46%	2.52%	0.15%	2.67%	0.21%
344.00 Generators and Devices	4.45%	0.22%	4.67%	4.27%	0.20%	4.47%	-0.20%
345.00 Accessory Electric Equipment	2.41%	0.13%	2.54%	2.60%	0.15%	2.75%	0.21%
346.00 Miscellaneous Power Plant Equipment	2.85%	0.15%	3.00%	4.40%	0.20%	4.60%	1.60%
Total Sun Dance Units 1-10	2.46%	0.13%	2.59%	2.66%	0.15%	2.81%	0.22%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	6.05%	0.46%	6.51%	6.97%	0.28%	7.25%	0.74%
342.00 Fuel Holders, Products and Accessories	3.36%	0.17%	3.53%	4.99%	0.16%	5.15%	1.62%
343.00 Prime Movers	5.03%	0.49%	5.52%	6.11%	0.22%	6.33%	0.81%
344.00 Generators and Devices	4.80%	0.29%	5.09%	6.74%	0.26%	7.00%	1.91%
345.00 Accessory Electric Equipment	2.61%	0.13%	2.74%	5.17%	0.17%	5.34%	2.60%
346.00 Miscellaneous Power Plant Equipment	3.52%	0.26%	3.78%	5.07%	0.17%	5.24%	1.46%
Total West Phoenix CT Units 1-2	4.86%	0.39%	5.25%	6.31%	0.23%	6.54%	1.29%
Yucca							
341.00 Structures and Improvements	4.72%	0.29%	5.01%	5.53%	0.24%	5.77%	0.76%
342.00 Fuel Holders, Products and Accessories	1.86%	0.10%	1.96%	2.84%	0.13%	2.97%	1.01%
343.00 Prime Movers	2.98%	0.20%	3.18%	3.31%	0.13%	3.44%	0.26%
344.00 Generators and Devices	3.36%	0.21%	3.57%	4.31%	0.19%	4.50%	0.93%
345.00 Accessory Electric Equipment	2.94%	0.26%	3.20%	3.80%	0.16%	3.96%	0.76%
346.00 Miscellaneous Power Plant Equipment	2.93%	0.15%	3.08%	3.88%	0.16%	4.04%	0.96%
Total Yucca	3.06%	0.20%	3.26%	3.55%	0.14%	3.69%	0.43%

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Statement A

Account Description	Current			SFAS 143 Method			Difference
	Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D=B+C	E	F	G=E+F	H=G-D
Yucca CT Units 1-4							
341.00 Structures and Improvements	4.99%	0.31%	5.30%	5.94%	0.26%	6.20%	0.90%
342.00 Fuel Holders, Products and Accessories	1.42%	0.08%	1.50%	2.74%	0.14%	2.88%	1.38%
343.00 Prime Movers	2.80%	0.44%	3.24%	4.31%	0.18%	4.49%	1.25%
344.00 Generators and Devices	3.36%	0.21%	3.57%	4.33%	0.19%	4.52%	0.95%
345.00 Accessory Electric Equipment	2.84%	0.27%	3.11%	3.86%	0.17%	4.03%	0.92%
346.00 Miscellaneous Power Plant Equipment	2.38%	0.12%	2.50%	3.91%	0.17%	4.08%	1.58%
Total Yucca CT Units 1-4	3.12%	0.29%	3.41%	4.34%	0.19%	4.53%	1.12%
Yucca CT Units 5-6							
341.00 Structures and Improvements	3.29%	0.17%	3.46%	3.37%	0.13%	3.50%	0.04%
342.00 Fuel Holders, Products and Accessories	3.01%	0.15%	3.16%	3.10%	0.12%	3.22%	0.06%
343.00 Prime Movers	3.01%	0.15%	3.16%	3.13%	0.12%	3.25%	0.09%
344.00 Generators and Devices	3.14%	0.16%	3.30%	3.45%	0.14%	3.59%	0.29%
345.00 Accessory Electric Equipment	3.41%	0.23%	3.64%	3.51%	0.14%	3.65%	0.01%
346.00 Miscellaneous Power Plant Equipment	3.70%	0.19%	3.89%	3.83%	0.15%	3.98%	0.09%
Total Yucca CT Units 5-6	3.03%	0.15%	3.18%	3.15%	0.12%	3.27%	0.09%
Solar Units							
341.00 Structures and Improvements	3.54%	0.25%	3.79%	3.44%	0.25%	3.69%	-0.10%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	3.57%	0.25%	3.81%	3.50%	0.26%	3.76%	-0.05%
345.00 Accessory Electric Equipment	3.54%	0.23%	3.77%	3.52%	0.26%	3.78%	0.01%
346.00 Miscellaneous Power Plant Equipment	3.91%	0.35%	4.26%	3.36%	0.25%	3.61%	-0.65%
Total Solar Units	3.56%	0.25%	3.81%	3.50%	0.26%	3.76%	-0.05%
Chino Valley							
341.05 Structures and Improvements	3.53%	0.26%	3.79%	3.52%	0.21%	3.73%	-0.06%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.53%	0.26%	3.79%	3.52%	0.21%	3.73%	-0.06%
345.05 Accessory Electric Equipment	3.53%	0.26%	3.79%	3.52%	0.21%	3.73%	-0.06%
346.05 Miscellaneous Power Plant Equipment	3.53%	0.26%	3.79%	3.52%	0.21%	3.73%	-0.06%
Total Chino Valley	3.53%	0.26%	3.79%	3.52%	0.21%	3.73%	-0.06%
Cotton Center							
341.05 Structures and Improvements	3.52%	0.24%	3.76%	3.47%	0.19%	3.66%	-0.10%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.52%	0.24%	3.76%	3.50%	0.19%	3.69%	-0.07%
345.05 Accessory Electric Equipment	3.52%	0.24%	3.76%	3.47%	0.19%	3.66%	-0.10%
346.05 Miscellaneous Power Plant Equipment	3.52%	0.24%	3.76%	3.47%	0.19%	3.66%	-0.10%
Total Cotton Center	3.52%	0.24%	3.76%	3.49%	0.19%	3.68%	-0.08%
Desert Star							
341.05 Structures and Improvements	4.51%	0.52%	5.03%	2.95%	0.29%	3.24%	-1.79%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	4.51%	0.52%	5.03%	3.10%	0.29%	3.39%	-1.64%
345.05 Accessory Electric Equipment	4.51%	0.52%	5.03%	2.95%	0.29%	3.24%	-1.79%
346.05 Miscellaneous Power Plant Equipment	4.51%	0.52%	5.03%	2.95%	0.29%	3.24%	-1.79%
Total Desert Star	4.51%	0.52%	5.03%	3.07%	0.29%	3.36%	-1.67%

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Statement A

Account Description	Current			SFAS 143 Method			Difference
	Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D=B+C	E	F	G=E+F	H=G-D
Foothills Units							
341.05 Structures and Improvements	3.48%	0.30%	3.78%	3.47%	0.23%	3.70%	-0.08%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.48%	0.30%	3.78%	3.47%	0.23%	3.70%	-0.08%
345.05 Accessory Electric Equipment	3.48%	0.30%	3.78%	3.47%	0.23%	3.70%	-0.08%
346.05 Miscellaneous Power Plant Equipment	3.48%	0.30%	3.78%	3.47%	0.23%	3.70%	-0.08%
Total Foothills Units	3.48%	0.30%	3.78%	3.47%	0.23%	3.70%	-0.08%
Gila Bend							
341.05 Structures and Improvements	3.46%	0.36%	3.82%	3.43%	0.27%	3.70%	-0.12%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.46%	0.36%	3.82%	3.43%	0.27%	3.70%	-0.12%
345.05 Accessory Electric Equipment	3.46%	0.36%	3.82%	3.43%	0.27%	3.70%	-0.12%
346.05 Miscellaneous Power Plant Equipment	3.46%	0.36%	3.82%	3.43%	0.27%	3.70%	-0.12%
Total Gila Bend	3.46%	0.36%	3.82%	3.43%	0.27%	3.70%	-0.12%
Hyder							
341.05 Structures and Improvements	3.51%	0.16%	3.67%	3.50%	0.12%	3.62%	-0.05%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.50%	0.16%	3.66%	3.49%	0.12%	3.61%	-0.05%
345.05 Accessory Electric Equipment	3.48%	0.16%	3.64%	3.47%	0.12%	3.59%	-0.05%
346.05 Miscellaneous Power Plant Equipment	3.42%	0.15%	3.57%	3.40%	0.12%	3.52%	-0.05%
Total Hyder	3.50%	0.16%	3.66%	3.49%	0.12%	3.61%	-0.05%
Legacy							
341.00 Structures and Improvements	1.31%	0.03%	1.34%	-0.41%	0.01%	-0.40%	-1.74%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	3.44%	0.08%	3.52%	2.56%	0.01%	2.57%	-0.95%
345.00 Accessory Electric Equipment	4.23%	0.22%	4.45%	3.22%	0.02%	3.24%	-1.21%
346.00 Miscellaneous Power Plant Equipment							
Total Legacy	3.51%	0.10%	3.61%	2.59%	0.01%	2.60%	-1.01%
Luke AFB							
341.05 Structures and Improvements	4.51%	0.54%	5.05%	3.40%	0.34%	3.74%	-1.31%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	4.51%	0.54%	5.05%	3.40%	0.34%	3.74%	-1.31%
345.05 Accessory Electric Equipment	4.51%	0.54%	5.05%	3.40%	0.34%	3.74%	-1.31%
346.05 Miscellaneous Power Plant Equipment	4.51%	0.54%	5.05%	3.40%	0.34%	3.74%	-1.31%
Total Luke AFB	4.51%	0.54%	5.05%	3.40%	0.34%	3.74%	-1.31%
Paloma							
341.05 Structures and Improvements	3.52%	0.30%	3.82%	3.51%	0.24%	3.75%	-0.07%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.52%	0.30%	3.82%	3.52%	0.24%	3.76%	-0.06%
345.05 Accessory Electric Equipment	3.52%	0.30%	3.82%	3.51%	0.24%	3.75%	-0.07%
346.05 Miscellaneous Power Plant Equipment	3.52%	0.30%	3.82%	3.51%	0.24%	3.75%	-0.07%
Total Paloma	3.52%	0.30%	3.82%	3.52%	0.24%	3.76%	-0.06%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Depreciation Accrual Rates - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	Current			SFAS 143 Method			Difference
	Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D=B+C	E	F	G=E+F	H=G-D
Red Rock							
341.05 Structures and Improvements	3.33%		3.33%	3.60%	0.39%	3.99%	0.66%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.33%		3.33%	3.60%	0.39%	3.99%	0.66%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.60%	0.39%	3.99%	0.66%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.60%	0.39%	3.99%	0.66%
Total Redrock	3.33%		3.33%	3.60%	0.39%	3.99%	0.66%
Roof Tops							
341.05 Structures and Improvements	3.53%	0.18%	3.71%	3.70%	0.47%	4.17%	0.46%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	3.55%	0.18%	3.73%	3.81%	0.48%	4.29%	0.56%
345.05 Accessory Electric Equipment	3.54%	0.18%	3.72%	3.88%	0.49%	4.37%	0.65%
346.05 Miscellaneous Power Plant Equipment							
Total Roof Tops	3.55%	0.18%	3.73%	3.82%	0.48%	4.30%	0.57%

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current			SFAS 143 Method			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION								
311.00 Structures and Improvements	$ 141,937,433	$ 7,116,777	$ 556,174	$ 7,672,951	$ 8,285,427	$ 455,902	$ 8,741,329	$ 1,068,378
312.00 Boiler Plant Equipment	1,491,411,135	43,316,033	4,965,341	48,281,374	65,147,444	5,598,916	70,746,360	22,464,986
314.00 Turbogenerator Units	211,425,539	7,675,326	764,743	8,440,069	10,262,109	784,691	11,046,800	2,606,731
315.00 Accessory Electric Equipment	117,866,116	5,015,509	488,047	5,503,556	5,808,945	374,370	6,183,315	679,759
316.00 Miscellaneous Power Plant Equipment	84,425,866	3,206,651	362,500	3,569,151	3,843,616	295,578	4,139,194	570,043
Total Steam Production Plant	$ 2,047,066,089	$ 66,330,296	$ 7,136,805	$ 73,467,101	$ 93,347,541	$ 7,509,457	$ 100,856,998	$ 27,389,897
NUCLEAR PRODUCTION								
321.00 Structures and Improvements	$ 850,120,585	$ 8,353,862	$ 107,082	$ 8,460,944	$ 10,333,638	$ 85,013	$ 10,418,651	$ 1,957,707
322.00 Reactor Plant Equipment	1,187,263,758	9,081,206	737,370	9,818,576	8,901,467	428,307	9,329,774	(488,802)
323.00 Turbogenerator Units	405,048,258	3,596,722	128,395	3,725,117	4,359,762	40,505	4,400,267	675,150
324.00 Accessory Electric Equipment	294,782,526	1,139,638	17,347	1,156,985	1,427,391	29,479	1,456,870	299,885
325.00 Miscellaneous Power Plant Equipment	233,949,471	3,258,152	119,194	3,377,346	4,070,666	23,395	4,094,061	716,715
Total Nuclear Production Plant	$ 2,971,164,598	$ 25,429,580	$ 1,109,388	$ 26,538,968	$ 29,092,924	$ 606,699	$ 29,699,623	$ 3,160,655
OTHER PRODUCTION								
341.00 Structures and Improvements	$ 131,575,027	$ 4,650,609	$ 324,073	$ 4,974,682	$ 5,029,148	$ 255,690	$ 5,284,838	$ 310,156
342.00 Fuel Holders, Products and Accessories	56,786,945	2,047,133	104,977	2,152,110	2,213,412	100,377	2,313,789	161,679
343.00 Prime Movers	655,542,039	21,587,034	1,010,774	22,597,808	22,893,055	1,019,332	23,912,387	1,314,579
344.00 Generators and Devices	2,104,937,839	77,968,261	1,545,723	79,513,984	80,127,616	3,984,664	84,112,280	4,598,296
345.00 Accessory Electric Equipment	247,553,984	9,267,556	572,772	9,840,328	9,631,025	559,992	10,191,017	350,689
346.00 Miscellaneous Power Plant Equipment	34,845,144	1,376,440	71,011	1,447,451	1,601,404	69,761	1,671,165	223,714
Total Other Production Plant	$ 3,231,240,978	$ 116,897,033	$ 3,629,330	$ 120,526,363	$ 121,495,660	$ 5,989,816	$ 127,485,476	$ 6,959,113
TRANSMISSION PLANT								
352.02 Structures and Improvements	$ 151,995	$ 3,815	$ -	$ 3,815	$ 3,769	$ -	$ 3,769	$ (46)
353.00 Station Equipment	132,434,328	2,529,496	119,191	2,648,687	2,516,252	92,704	2,608,956	(39,731)
354.00 Towers and Fixtures	1,329,316	23,662		23,662	23,529		23,529	(133)
355.00 Poles and Fixtures	1,370,085	25,347	5,069	30,416	25,347	3,562	28,909	(1,507)
356.00 Overhead Conductors and Devices	1,947,677	33,890	6,427	40,317	34,084	4,869	38,953	(1,364)
Total Transmission Plant	$ 137,233,401	$ 2,616,210	$ 130,687	$ 2,746,897	$ 2,602,981	$ 101,135	$ 2,704,116	$ (42,781)
DISTRIBUTION PLANT								
361.00 Structures and Improvements	$ 93,053,192	$ 1,470,240	$ 74,443	$ 1,544,683	$ 1,479,546	$ 93,053	$ 1,572,599	$ 27,916
362.00 Station Equipment	631,870,595	13,901,153	505,496	14,406,649	13,522,031	631,871	14,153,902	(252,747)
363.00 Storage Battery Equipment	13,585,353	1,194,153		1,194,153	1,325,930		1,325,930	131,777
364.01 Poles, Towers and Fixtures - Wood	357,345,350	7,504,252	678,956	8,183,208	7,575,721	1,322,178	8,897,899	714,691
364.02 Poles, Towers and Fixtures - Steel	323,911,866	6,316,281	615,433	6,931,714	6,316,281	485,868	6,802,149	(129,565)
365.00 Overhead Conductors and Devices	468,658,341	8,998,240	937,317	9,935,557	9,091,972	1,452,841	10,544,813	609,256
366.00 Underground Conduit	727,611,816	11,423,506	1,236,940	12,660,446	11,496,267	1,455,224	12,951,491	291,045

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
367.00 Underground Conductors and Devices	1,863,851,442	43,614,124	3,727,703	47,341,827	43,986,894	5,964,325	49,951,219	2,609,392
368.00 Line Transformers	921,018,156	15,657,309	552,611	16,209,920	15,933,614	736,815	16,670,429	460,509
369.00 Services	447,263,911	7,514,034	1,475,971	8,990,005	7,603,486	1,297,065	8,900,551	(89,454)
370.01 Meters - Electronic	17,843,353	984,953	(5,353)	979,600	1,058,111		1,058,111	78,511
370.03 Meters - AMI	302,666,385	14,649,053		14,649,053	18,462,649		18,462,649	3,813,596
371.00 Installations on Customers' Premises	46,529,246	981,767	144,241	1,126,008	986,420	130,282	1,116,702	(9,306)
373.00 Street Lighting and Signal Systems	80,127,587	1,378,194	144,230	1,522,424	1,394,220	176,281	1,570,501	48,077
Total Distribution Plant	$ 6,295,336,593	$ 135,587,259	$ 10,087,988	$ 145,675,247	$ 140,233,142	$ 13,745,803	$ 153,978,945	$ 8,303,698
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$ 265,654,498	$ 6,694,493	$ 451,613	$ 7,146,106	$ 6,667,928	$ 557,874	$ 7,225,802	$ 79,696
391.CM Office Furn. and Equip. - Computer	243,545,219	31,319,915	48,709	31,368,624	29,785,580		29,785,580	(1,583,044)
397.00 Communication Equipment	295,372,374	14,266,486		14,266,486	14,000,651		14,000,651	(265,835)
Total Depreciable	$ 804,572,091	$ 52,280,894	$ 500,322	$ 52,781,216	$ 50,454,159	$ 557,874	$ 51,012,033	$ (1,769,183)
Amortizable								
391.FE Office Furn. and Equip. - Furniture	$ 63,799,361	$ 3,179,056	$ -	$ 3,179,056	$ 3,179,056	$ -	$ 3,179,056	$ -
393.00 Stores Equipment	594,181	29,709		29,709	29,709		29,709	
394.00 Tools, Shop and Garage Equipment	43,094,855	2,147,617		2,147,617	2,147,617		2,147,617	
395.00 Laboratory Equipment	767,547	38,377		38,377	38,377		38,377	
398.00 Miscellaneous Equipment	23,861,303	994,221		994,221	994,221		994,221	
Total Amortizable	$ 132,117,247	$ 6,388,980	$ -	$ 6,388,980	$ 6,388,980	$ -	$ 6,388,980	$ -
Total General Plant	$ 936,689,338	$ 58,669,874	$ 500,322	$ 59,170,196	$ 56,843,139	$ 557,874	$ 57,401,013	$ (1,769,183)
TOTAL UTILITY	$ 15,618,730,997	$ 405,530,252	$ 22,594,520	$ 428,124,772	$ 443,615,387	$ 28,510,784	$ 472,126,171	$ 44,001,399
STEAM PRODUCTION (by Unit)								
Cholla								
311.00 Structures and Improvements	$ 78,078,473	$ 5,504,450	$ 394,240	$ 5,898,690	$ 6,496,408	$ 277,097	$ 6,773,505	$ 874,815
312.00 Boiler Plant Equipment	385,237,434	27,018,838	2,231,038	29,249,876	31,352,178	1,545,816	32,897,994	3,648,118
314.00 Turbogenerator Units	85,554,772	5,671,879	388,323	6,060,202	6,458,300	324,135	6,782,435	722,233
315.00 Accessory Electric Equipment	53,298,558	3,259,945	234,003	3,493,948	3,816,758	167,707	3,984,465	490,517
316.00 Miscellaneous Power Plant Equipment	24,674,267	1,798,701	135,432	1,934,133	2,144,966	104,361	2,249,327	315,194
Total Cholla	$ 626,843,504	$ 43,253,813	$ 3,383,036	$ 46,636,849	$ 50,268,610	$ 2,419,116	$ 52,687,726	$ 6,050,877

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Cholla Unit 1								
311.00 Structures and Improvements	$ 4,743,207	$ 254,236	$ 20,870	$ 275,106	$ 282,695	$ 17,076	$ 299,771	$ 24,665
312.00 Boiler Plant Equipment	82,295,074	4,970,622	534,918	5,505,540	5,620,754	370,328	5,991,082	485,542
314.00 Turbogenerator Units	27,444,492	1,748,214	159,178	1,907,392	1,923,859	126,245	2,050,104	142,712
315.00 Accessory Electric Equipment	9,492,908	520,211	45,566	565,777	578,118	36,073	614,191	48,414
316.00 Miscellaneous Power Plant Equipment	3,742,187	192,723	16,840	209,563	257,837	16,466	274,303	64,740
Total Cholla Unit 1	$ 127,717,868	$ 7,686,006	$ 777,372	$ 8,463,378	$ 8,663,263	$ 566,188	$ 9,229,451	$ 766,073
Cholla Unit 3								
311.00 Structures and Improvements	$ 13,288,725	$ 932,868	$ 61,128	$ 993,996	$ 1,073,729	$ 43,853	$ 1,117,582	$ 123,586
312.00 Boiler Plant Equipment	243,068,426	17,695,381	1,336,876	19,032,257	20,612,203	947,967	21,560,170	2,527,913
314.00 Turbogenerator Units	57,062,305	3,834,587	222,543	4,057,130	4,445,154	194,012	4,639,166	582,036
315.00 Accessory Electric Equipment	34,899,789	2,090,497	146,579	2,237,076	2,425,535	94,229	2,519,764	282,688
316.00 Miscellaneous Power Plant Equipment	7,009,816	507,511	36,451	543,962	596,535	26,637	623,172	79,210
Total Cholla Unit 3	$ 355,329,061	$ 25,060,844	$ 1,803,577	$ 26,864,421	$ 29,153,156	$ 1,306,698	$ 30,459,854	$ 3,595,433
Cholla Common								
311.00 Structures and Improvements	$ 60,046,541	$ 4,317,346	$ 312,242	$ 4,629,588	$ 5,139,984	$ 216,168	$ 5,356,152	$ 726,564
312.00 Boiler Plant Equipment	59,873,934	4,352,835	359,244	4,712,079	5,119,221	227,521	5,346,742	634,663
314.00 Turbogenerator Units	1,047,975	89,078	6,602	95,680	89,287	3,878	93,165	(2,515)
315.00 Accessory Electric Equipment	8,905,861	649,237	41,858	691,095	813,105	37,405	850,510	159,415
316.00 Miscellaneous Power Plant Equipment	13,922,264	1,098,467	82,141	1,180,608	1,290,594	61,258	1,351,852	171,244
Total Cholla Common	$ 143,796,575	$ 10,506,963	$ 802,087	$ 11,309,050	$ 12,452,191	$ 546,230	$ 12,998,421	$ 1,689,371
Four Corners								
311.00 Structures and Improvements	$ 63,858,960	$ 1,612,327	$ 161,934	$ 1,774,261	$ 1,789,019	$ 178,805	$ 1,967,824	$ 193,563
312.00 Boiler Plant Equipment	1,106,173,701	16,297,195	2,734,303	19,031,498	33,795,266	4,053,100	37,848,366	18,816,868
314.00 Turbogenerator Units	125,870,767	2,003,447	376,420	2,379,867	3,803,809	460,556	4,264,365	1,884,498
315.00 Accessory Electric Equipment	64,567,558	1,755,564	254,044	2,009,608	1,992,187	206,663	2,198,850	189,242
316.00 Miscellaneous Power Plant Equipment	59,751,599	1,407,950	227,068	1,635,018	1,698,650	191,217	1,889,867	254,849
Total Four Corners	$ 1,420,222,585	$ 23,076,483	$ 3,753,769	$ 26,830,252	$ 43,078,931	$ 5,090,341	$ 48,169,272	$ 21,339,020
Four Corners Units 4-5								
311.00 Structures and Improvements	$ 39,839,762	$ 697,196	$ 123,503	$ 820,699	$ 748,988	$ 111,551	$ 860,539	$ 39,840
312.00 Boiler Plant Equipment	1,066,430,407	14,930,026	2,559,433	17,489,459	32,312,841	3,945,793	36,258,634	18,769,175
314.00 Turbogenerator Units	121,897,287	1,889,408	365,692	2,255,100	3,669,108	451,020	4,120,128	1,865,028
315.00 Accessory Electric Equipment	43,201,151	915,864	177,125	1,092,989	1,062,748	142,564	1,205,312	112,323
316.00 Miscellaneous Power Plant Equipment	39,853,780	805,046	159,415	964,461	936,564	135,503	1,072,067	107,606
Total Four Corners Units 4-5	$ 1,311,222,387	$ 19,237,540	$ 3,385,168	$ 22,622,708	$ 38,730,249	$ 4,786,431	$ 43,516,680	$ 20,893,972

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Four Corners Common								
311.00 Structures and Improvements	$ 24,019,198	$ 915,131	$ 38,431	$ 953,562	$ 1,040,031	$ 67,254	$ 1,107,285	$ 153,723
312.00 Boiler Plant Equipment	39,743,294	1,367,169	174,870	1,542,039	1,482,425	107,307	1,589,732	47,693
314.00 Turbogenerator Units	3,973,480	114,039	10,728	124,767	134,701	9,536	144,237	19,470
315.00 Accessory Electric Equipment	21,366,407	839,700	76,919	916,619	929,439	64,099	993,538	76,919
316.00 Miscellaneous Power Plant Equipment	19,897,819	602,904	67,653	670,557	762,086	55,714	817,800	147,243
Total Four Corners Common	$ 109,000,198	$ 3,838,943	$ 368,601	$ 4,207,544	$ 4,348,682	$ 303,910	$ 4,652,592	$ 445,048
NUCLEAR PRODUCTION (by Unit)								
Palo Verde								
321.00 Structures and Improvements	$ 850,120,585	$ 8,353,862	$ 107,082	$ 8,460,944	$ 10,333,638	$ 85,013	$ 10,418,651	$ 1,957,707
322.00 Reactor Plant Equipment	1,187,263,758	9,081,206	737,370	9,818,576	8,901,467	428,307	9,329,774	(488,802)
323.00 Turbogenerator Units	405,048,258	3,596,722	128,395	3,725,117	4,359,762	40,505	4,400,267	675,150
324.00 Accessory Electric Equipment	294,782,526	1,139,638	17,347	1,156,985	1,427,391	29,479	1,456,870	299,885
325.00 Miscellaneous Power Plant Equipment	233,949,471	3,258,152	119,194	3,377,346	4,070,666	23,395	4,094,061	716,715
Total Palo Verde	$ 2,971,164,598	$ 25,429,580	$ 1,109,388	$ 26,538,968	$ 29,092,924	$ 606,699	$ 29,699,623	$ 3,160,655
Palo Verde Unit 1								
321.00 Structures and Improvements	$ 169,287,979	$ 304,718	$ -	$ 304,718	$ 592,108	$ 16,929	$ 609,037	$ 304,319
322.00 Reactor Plant Equipment	465,986,593	2,795,920	46,599	2,842,519	2,737,718	139,796	2,877,514	34,995
323.00 Turbogenerator Units	144,321,116	1,140,137	72,161	1,212,298	1,473,720	14,432	1,488,152	275,854
324.00 Accessory Electric Equipment	121,319,415	230,507		230,507	330,540	12,132	342,672	112,165
325.00 Miscellaneous Power Plant Equipment	33,599,919	134,400	13,440	147,840	202,359	3,360	205,719	57,879
Total Palo Verde Unit 1	$ 934,515,022	$ 4,605,682	$ 132,200	$ 4,737,882	$ 5,336,445	$ 186,649	$ 5,523,094	$ 785,212
Palo Verde Unit 2								
321.00 Structures and Improvements	$ 94,477,904	$ 349,568	$ -	$ 349,568	$ 381,222	$ 9,448	$ 390,670	$ 41,102
322.00 Reactor Plant Equipment	248,880,636	2,389,254	149,328	2,538,582	2,315,376	99,552	2,414,928	(123,654)
323.00 Turbogenerator Units	87,819,612	974,798	26,346	1,001,144	1,018,129	8,782	1,026,911	25,767
324.00 Accessory Electric Equipment	49,752,711	233,838	4,975	238,813	261,131	4,975	266,106	27,293
325.00 Miscellaneous Power Plant Equipment	27,865,592	192,273	8,360	200,633	186,036	2,787	188,823	(11,810)
Total Palo Verde Unit 2	$ 508,796,455	$ 4,139,731	$ 189,009	$ 4,328,740	$ 4,161,894	$ 125,544	$ 4,287,438	$ (41,302)
Palo Verde Unit 3								
321.00 Structures and Improvements	$ 167,896,725	$ 486,901	$ -	$ 486,901	$ 476,365	$ 16,790	$ 493,155	$ 6,254
322.00 Reactor Plant Equipment	436,634,437	3,536,739	392,971	3,929,710	3,316,658	174,654	3,491,312	(438,398)
323.00 Turbogenerator Units	167,364,071	1,355,649	16,736	1,372,385	1,729,957	16,736	1,746,693	374,308
324.00 Accessory Electric Equipment	95,765,260	373,485	9,577	383,062	400,556	9,577	410,133	27,071
325.00 Miscellaneous Power Plant Equipment	29,878,581	164,332	11,951	176,283	165,943	2,988	168,931	(7,352)
Total Palo Verde Unit 3	$ 897,539,074	$ 5,917,106	$ 431,235	$ 6,348,341	$ 6,089,479	$ 220,745	$ 6,310,224	$ (38,117)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current			SFAS 143 Method			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Palo Verde Water Reclamation								
321.00 Structures and Improvements	$ 233,902,104	$ 4,794,993	$ 70,171	$ 4,865,164	$ 5,628,934	$ 23,390	$ 5,652,324	$ 787,160
322.00 Reactor Plant Equipment	454,911	13,283	182	13,465	13,926	182	14,108	643
323.00 Turbogenerator Units	217,756	3,114	370	3,484	3,821	22	3,843	359
324.00 Accessory Electric Equipment								
325.00 Miscellaneous Power Plant Equipment	241,107	5,280	24	5,304	6,552	24	6,576	1,272
Total Palo Verde Water Reclamation	$ 234,815,878	$ 4,816,670	$ 70,747	$ 4,887,417	$ 5,653,233	$ 23,618	$ 5,676,851	$ 789,434
Palo Verde Common								
321.00 Structures and Improvements	$ 184,555,873	$ 2,417,682	$ 36,911	$ 2,454,593	$ 3,255,009	$ 18,456	$ 3,273,465	$ 818,872
322.00 Reactor Plant Equipment	35,307,181	346,010	148,290	494,300	517,789	14,123	531,912	37,612
323.00 Turbogenerator Units	5,325,703	123,024	12,782	135,806	134,135	533	134,668	(1,138)
324.00 Accessory Electric Equipment	27,945,140	301,808	2,795	304,603	435,164	2,795	437,959	133,356
325.00 Miscellaneous Power Plant Equipment	142,364,272	2,761,867	85,419	2,847,286	3,509,776	14,236	3,524,012	676,726
Total Palo Verde Common	$ 395,498,169	$ 5,950,391	$ 286,197	$ 6,236,588	$ 7,851,873	$ 50,143	$ 7,902,016	$ 1,665,428
OTHER PRODUCTION								
Combined Cycle								
341.00 Structures and Improvements	$ 63,600,586	$ 2,107,372	$ 131,304	$ 2,238,676	$ 2,315,277	$ 98,001	$ 2,413,278	$ 174,602
342.00 Fuel Holders, Products and Accessories	41,829,313	1,652,145	84,706	1,736,851	1,691,825	77,722	1,769,547	32,696
343.00 Prime Movers	274,702,584	10,121,342	539,819	10,661,161	9,886,864	397,825	10,284,689	(376,472)
344.00 Generators and Devices	727,795,468	29,917,431	(368,782)	29,548,649	32,412,315	1,333,957	33,746,272	4,197,623
345.00 Accessory Electric Equipment	78,442,697	3,449,660	201,290	3,650,950	3,707,582	159,964	3,867,546	216,596
346.00 Miscellaneous Power Plant Equipment	20,741,997	934,600	45,066	979,666	997,569	42,690	1,040,259	60,593
Total Combined Cycle	$ 1,207,112,645	$ 48,182,550	$ 633,403	$ 48,815,953	$ 51,011,432	$ 2,110,159	$ 53,121,591	$ 4,305,638
Redhawk CC Units 1-2								
341.00 Structures and Improvements	$ 23,988,173	$ 959,527	$ 47,976	$ 1,007,503	$ 906,753	$ 35,982	$ 942,735	$ (64,768)
342.00 Fuel Holders, Products and Accessories	12,809,613	559,780	29,462	589,242	568,747	23,057	591,804	2,562
343.00 Prime Movers	132,414,998	5,256,875	344,279	5,601,154	4,992,045	198,622	5,190,667	(410,487)
344.00 Generators and Devices	391,212,295	16,939,492	(430,334)	16,509,158	17,604,553	704,182	18,308,735	1,799,577
345.00 Accessory Electric Equipment	29,897,838	1,186,944	56,806	1,243,750	1,207,873	47,837	1,255,710	11,960
346.00 Miscellaneous Power Plant Equipment	6,872,469	303,076	13,745	316,821	303,076	12,370	315,446	(1,375)
Total Redhawk CC Units 1-2	$ 597,195,386	$ 25,205,694	$ 61,934	$ 25,267,628	$ 25,583,047	$ 1,022,050	$ 26,605,097	$ 1,337,469

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix								
341.00 Structures and Improvements	$ 39,612,413	$ 1,147,845	$ 83,328	$ 1,231,173	$ 1,408,524	$ 62,019	$ 1,470,543	$ 239,370
342.00 Fuel Holders, Products and Accessories	29,019,700	1,092,365	55,244	1,147,609	1,123,078	54,665	1,177,743	30,134
343.00 Prime Movers	142,287,586	4,864,467	195,540	5,060,007	4,894,819	199,203	5,094,022	34,015
344.00 Generators and Devices	336,583,173	12,977,939	61,552	13,039,491	14,807,762	629,775	15,437,537	2,398,046
345.00 Accessory Electric Equipment	48,544,859	2,262,716	144,484	2,407,200	2,499,709	112,127	2,611,836	204,636
346.00 Miscellaneous Power Plant Equipment	13,869,528	631,524	31,321	662,845	694,493	30,320	724,813	61,968
Total West Phoenix	$ 609,917,259	$ 22,976,856	$ 571,469	$ 23,548,325	$ 25,428,385	$ 1,088,109	$ 26,516,494	$ 2,968,169
West Phoenix CC Units 1-3								
341.00 Structures and Improvements	$ 366,217	$ 14,759	$ 696	$ 15,455	$ 15,381	$ 732	$ 16,113	$ 658
342.00 Fuel Holders, Products and Accessories	22,031,967	868,059	44,064	912,123	823,996	41,861	865,857	(46,266)
343.00 Prime Movers								
344.00 Generators and Devices	130,345,213	5,213,809	182,483	5,396,292	6,465,123	299,794	6,764,917	1,368,625
345.00 Accessory Electric Equipment	32,620,455	1,699,526	114,172	1,813,698	1,891,986	88,075	1,980,061	166,363
346.00 Miscellaneous Power Plant Equipment	8,073,969	389,165	18,570	407,735	440,839	20,185	461,024	53,289
Total West Phoenix CC Units 1-3	$ 193,437,821	$ 8,185,318	$ 359,985	$ 8,545,303	$ 9,637,325	$ 450,647	$ 10,087,972	$ 1,542,669
West Phoenix CC Unit 4								
341.00 Structures and Improvements	$ 7,035,987	$ 232,188	$ 11,961	$ 244,149	$ 284,254	$ 11,961	$ 296,215	$ 52,066
342.00 Fuel Holders, Products and Accessories	4,470,010	143,487	7,152	150,639	143,487	6,258	149,745	(894)
343.00 Prime Movers	49,464,010	1,587,795	9,893	1,597,688	1,553,170	69,250	1,622,420	24,732
344.00 Generators and Devices	23,956,815	910,359	43,122	953,481	905,568	38,331	943,899	(9,582)
345.00 Accessory Electric Equipment	552,377	22,095	1,105	23,200	23,586	994	24,580	1,380
346.00 Miscellaneous Power Plant Equipment	942,600	42,417	2,074	44,491	44,491	1,885	46,376	1,885
Total West Phoenix CC Unit 4	$ 86,421,799	$ 2,938,341	$ 75,307	$ 3,013,648	$ 2,954,556	$ 128,679	$ 3,083,235	$ 69,587
West Phoenix CC Unit 5								
341.00 Structures and Improvements	$ 11,054,705	$ 384,704	$ 19,898	$ 404,602	$ 400,180	$ 15,477	$ 415,657	$ 11,055
342.00 Fuel Holders, Products and Accessories	2,517,723	80,819	4,028	84,847	155,595	6,546	162,141	77,294
343.00 Prime Movers	92,823,576	3,276,672	185,647	3,462,319	3,341,649	129,953	3,471,602	9,283
344.00 Generators and Devices	182,281,145	6,853,771	(164,053)	6,689,718	7,437,071	291,650	7,728,721	1,039,003
345.00 Accessory Electric Equipment	15,372,027	541,095	29,207	570,302	584,137	23,058	607,195	36,893
346.00 Miscellaneous Power Plant Equipment	4,852,959	199,942	10,677	210,619	209,163	8,250	217,413	6,794
Total West Phoenix CC Unit 5	$ 308,902,135	$ 11,337,003	$ 85,404	$ 11,422,407	$ 12,127,795	$ 474,934	$ 12,602,729	$ 1,180,322

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix Common								
341.00 Structures and Improvements	$ 21,155,504	$ 516,194	$ 50,773	$ 566,967	$ 708,709	$ 33,849	$ 742,558	$ 175,591
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices								
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total West Phoenix Common	$ 21,155,504	$ 516,194	$ 50,773	$ 566,967	$ 708,709	$ 33,849	$ 742,558	$ 175,591
Combustion Turbine								
341.00 Structures and Improvements	$ 31,102,449	$ 1,238,442	$ 99,263	$ 1,337,705	$ 1,445,015	$ 66,256	$ 1,511,271	$ 173,566
342.00 Fuel Holders, Products and Accessories	14,957,632	394,988	20,271	415,259	521,587	22,655	544,242	128,983
343.00 Prime Movers	380,839,455	11,465,692	470,955	11,936,647	13,006,191	621,507	13,627,698	1,691,051
344.00 Generators and Devices	689,863,781	23,548,896	199,699	23,748,595	23,680,823	852,882	24,533,705	785,110
345.00 Accessory Electric Equipment	42,078,140	1,319,888	75,988	1,395,876	1,452,194	68,791	1,520,985	125,109
346.00 Miscellaneous Power Plant Equipment	12,525,501	380,177	20,381	400,558	550,801	23,160	573,961	173,403
Total Combustion Turbine	$ 1,171,366,958	$ 38,348,083	$ 886,557	$ 39,234,640	$ 40,656,611	$ 1,655,251	$ 42,311,862	$ 3,077,222
Douglas CT								
341.00 Structures and Improvements	$ 103,952	$ 16,767	$ 842	$ 17,609	$ 9,512	$ 229	$ 9,741	$ (7,868)
342.00 Fuel Holders, Products and Accessories	137,759	33,186	1,488	34,674	12,812	193	13,005	(21,669)
343.00 Prime Movers	3,721,569	423,142	(341,268)	81,874	336,802	10,048	346,850	264,976
344.00 Generators and Devices	971,924	184,374	9,233	193,607	89,320	1,749	91,069	(102,538)
345.00 Accessory Electric Equipment	582,402	137,097	6,348	143,445	53,348	1,107	54,455	(88,990)
346.00 Miscellaneous Power Plant Equipment	33,564	8,082	430	8,512	3,121	47	3,168	(5,344)
Total Douglas CT	$ 5,551,170	$ 802,648	$ (322,927)	$ 479,721	$ 504,915	$ 13,373	$ 518,288	$ 38,567
Ocotillo								
341.00 Structures and Improvements	$ 3,189,602	$ 175,428	$ 15,310	$ 190,738	$ 227,419	$ 9,250	$ 236,669	$ -
342.00 Fuel Holders, Products and Accessories	1,484,432	55,221	2,820	58,041	86,839	3,117	89,956	45,931
343.00 Prime Movers	24,161,626	1,307,144	169,131	1,476,275	1,570,506	60,404	1,630,910	31,915
344.00 Generators and Devices	612,033,648	20,597,536	38,717	20,636,253	19,988,478	691,822	20,680,300	154,635
345.00 Accessory Electric Equipment	4,017,658	194,455	10,848	205,303	238,649	8,437	247,086	44,047
346.00 Miscellaneous Power Plant Equipment	950,460	39,729	1,901	41,630	50,850	1,711	52,561	41,783
Total Ocotillo	$ 645,837,426	$ 22,369,513	$ 238,727	$ 22,608,240	$ 22,162,741	$ 774,741	$ 22,937,482	$ 318,311

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Ocotillo CT Units 1-2								
341.00 Structures and Improvements	$ 3,189,602	$ 175,428	$ 15,310	$ 190,738	$ 227,419	$ 9,250	$ 236,669	$ 45,931
342.00 Fuel Holders, Products and Accessories	1,484,432	55,221	2,820	58,041	86,839	3,117	89,956	31,915
343.00 Prime Movers	24,161,626	1,307,144	169,131	1,476,275	1,570,506	60,404	1,630,910	154,635
344.00 Generators and Devices	15,486,821	732,527	38,717	771,244	958,634	35,620	994,254	223,010
345.00 Accessory Electric Equipment	4,017,658	194,455	10,848	205,303	238,649	8,437	247,086	41,783
346.00 Miscellaneous Power Plant Equipment	950,460	39,729	1,901	41,630	50,850	1,711	52,561	10,931
Total Octillo CT Units 1-2	$ 49,290,599	$ 2,504,504	$ 238,727	$ 2,743,231	$ 3,132,897	$ 118,539	$ 3,251,436	$ 508,205
Ocotillo CT Units 3-7								
341.00 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	596,546,827	19,865,009		19,865,009	19,029,844	656,202	19,686,046	(178,963)
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total Octillo CT Units 3-7	$ 596,546,827	$ 19,865,009	$ -	$ 19,865,009	$ 19,029,844	$ 656,202	$ 19,686,046	$ (178,963)
Saguaro								
341.00 Structures and Improvements	$ 3,051,365	$ 128,157	$ 12,511	$ 140,668	$ 164,469	$ 6,713	$ 171,182	$ 30,514
342.00 Fuel Holders, Products and Accessories	1,642,488	35,478	2,135	37,613	61,758	2,464	64,222	26,609
343.00 Prime Movers	23,292,483	952,858	110,645	1,063,503	1,411,374	59,009	1,470,383	406,880
344.00 Generators and Devices	38,498,152	1,116,094	57,748	1,173,842	1,583,134	74,511	1,657,645	483,803
345.00 Accessory Electric Equipment	3,593,189	144,412	8,691	153,103	185,445	7,449	192,894	39,791
346.00 Miscellaneous Power Plant Equipment	916,172	20,614	1,008	21,622	36,189	1,466	37,655	16,033
Total Saguaro	$ 70,993,849	$ 2,397,613	$ 192,738	$ 2,590,351	$ 3,442,369	$ 151,612	$ 3,593,981	$ 1,003,630
Saguaro CT Units 1-2								
341.00 Structures and Improvements	$ 3,051,365	$ 128,157	$ 12,511	$ 140,668	$ 164,469	$ 6,713	$ 171,182	$ 30,514
342.00 Fuel Holders, Products and Accessories	1,642,488	35,478	2,135	37,613	61,758	2,464	64,222	26,609
343.00 Prime Movers	21,353,178	875,480	106,766	982,246	1,338,844	55,518	1,394,362	412,116
344.00 Generators and Devices	14,724,431	400,505	22,087	422,592	967,395	41,228	1,008,623	586,031
345.00 Accessory Electric Equipment	3,269,324	134,696	8,173	142,869	172,620	6,866	179,486	36,617
346.00 Miscellaneous Power Plant Equipment	916,172	20,614	1,008	21,622	36,189	1,466	37,655	16,033
Total Saguaro CT Units 1-2	$ 44,956,958	$ 1,594,930	$ 152,680	$ 1,747,610	$ 2,741,275	$ 114,255	$ 2,855,530	$ 1,107,920

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Saguaro CT Unit 3								
341.00 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	1,939,305	77,378	3,879	81,257	72,530	3,491	76,021	(5,236)
344.00 Generators and Devices	23,773,721	715,589	35,661	751,250	615,739	33,283	649,022	(102,228)
345.00 Accessory Electric Equipment	323,865	9,716	518	10,234	12,825	583	13,408	3,174
346.00 Miscellaneous Power Plant Equipment								
Total Saguaro CT Unit 3	$ 26,036,891	$ 802,683	$ 40,058	$ 842,741	$ 701,094	$ 37,357	$ 738,451	$ (104,290)
Sundance Units 1-10								
341.00 Structures and Improvements	$ 13,762,067	$ 342,675	$ 31,653	$ 374,328	$ 374,328	$ 22,019	$ 396,347	$ 22,019
342.00 Fuel Holders, Products and Accessories	4,418,231	108,247	5,302	113,549	113,990	6,627	120,617	7,068
343.00 Prime Movers	227,932,672	5,333,625	273,519	5,607,144	5,743,903	341,899	6,085,802	478,658
344.00 Generators and Devices	13,058,506	581,104	28,729	609,833	557,598	26,117	583,715	(26,118)
345.00 Accessory Electric Equipment	27,804,255	670,083	36,146	706,229	722,911	41,706	764,617	58,388
346.00 Miscellaneous Power Plant Equipment	6,970,933	198,672	10,456	209,128	306,721	13,942	320,663	111,535
Total Sun Dance Units 1-10	$ 293,946,664	$ 7,234,406	$ 385,805	$ 7,620,211	$ 7,819,451	$ 452,310	$ 8,271,761	$ 651,550
West Phoenix CT Units 1-2								
341.00 Structures and Improvements	$ 4,239,486	$ 256,489	$ 19,502	$ 275,991	$ 295,492	$ 11,871	$ 307,363	$ 31,372
342.00 Fuel Holders, Products and Accessories	1,843,219	61,932	3,133	65,065	91,977	2,949	94,926	29,861
343.00 Prime Movers	20,466,623	1,029,471	100,286	1,129,757	1,250,511	45,027	1,295,538	165,781
344.00 Generators and Devices	15,280,205	733,450	44,313	777,763	1,029,886	39,729	1,069,615	291,852
345.00 Accessory Electric Equipment	1,525,954	39,827	1,984	41,811	78,892	2,594	81,486	39,675
346.00 Miscellaneous Power Plant Equipment	1,026,473	36,132	2,669	38,801	52,042	1,745	53,787	14,986
Total West Phoenix CT Units 1-2	$ 44,381,960	$ 2,157,301	$ 171,887	$ 2,329,188	$ 2,798,800	$ 103,915	$ 2,902,715	$ 573,527
Yucca								
341.00 Structures and Improvements	$ 6,755,977	$ 318,926	$ 19,445	$ 338,371	$ 373,795	$ 16,174	$ 389,969	$ 51,598
342.00 Fuel Holders, Products and Accessories	5,431,503	100,924	5,393	106,317	154,211	7,305	161,516	55,199
343.00 Prime Movers	81,264,482	2,419,452	158,642	2,578,094	2,693,095	105,120	2,798,215	220,121
344.00 Generators and Devices	10,021,346	336,338	20,959	357,297	432,407	18,954	451,361	94,064
345.00 Accessory Electric Equipment	4,554,682	134,014	11,971	145,985	172,949	7,498	180,447	34,462
346.00 Miscellaneous Power Plant Equipment	2,627,899	76,948	3,917	80,865	101,878	4,249	106,127	25,262
Total Yucca	$ 110,655,889	$ 3,386,602	$ 220,327	$ 3,606,929	$ 3,928,335	$ 159,300	$ 4,087,635	$ 480,706

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Yucca CT Units 1-4								
341.00 Structures and Improvements	$ 5,685,548	$ 283,709	$ 17,625	$ 301,334	$ 337,722	$ 14,782	$ 352,504	$ 51,170
342.00 Fuel Holders, Products and Accessories	3,934,860	55,875	3,148	59,023	107,815	5,509	113,324	54,301
343.00 Prime Movers	12,670,962	354,787	55,752	410,539	546,118	22,808	568,926	158,387
344.00 Generators and Devices	9,848,867	330,922	20,683	351,605	426,456	18,713	445,169	93,564
345.00 Accessory Electric Equipment	3,737,069	106,133	10,090	116,223	144,251	6,353	150,604	34,381
346.00 Miscellaneous Power Plant Equipment	1,536,718	36,574	1,844	38,418	60,086	2,612	62,698	24,280
Total Yucca CT Units 1-4	$ 37,414,024	$ 1,168,000	$ 109,142	$ 1,277,142	$ 1,622,448	$ 70,777	$ 1,693,225	$ 416,083
Yucca CT Units 5-6								
341.00 Structures and Improvements	$ 1,070,429	$ 35,217	$ 1,820	$ 37,037	$ 36,073	$ 1,392	$ 37,465	$ 428
342.00 Fuel Holders, Products and Accessories	1,496,643	45,049	2,245	47,294	46,396	1,796	48,192	898
343.00 Prime Movers	68,593,520	2,064,665	102,890	2,167,555	2,146,977	82,312	2,229,289	61,734
344.00 Generators and Devices	172,479	5,416	276	5,692	5,951	241	6,192	500
345.00 Accessory Electric Equipment	817,613	27,881	1,881	29,762	28,698	1,145	29,843	81
346.00 Miscellaneous Power Plant Equipment	1,091,181	40,374	2,073	42,447	41,792	1,637	43,429	982
Total Yucca CT Units 5-6	$ 73,241,865	$ 2,218,602	$ 111,185	$ 2,329,787	$ 2,305,887	$ 88,523	$ 2,394,410	$ 64,623
Solar Units								
341.00 Structures and Improvements	$ 36,871,992	$ 1,304,795	$ 93,506	$ 1,398,301	$ 1,268,856	$ 91,433	$ 1,360,289	$ (38,012)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	687,278,590	24,501,934	1,714,806	26,216,740	24,034,478	1,797,825	25,832,303	(384,437)
345.00 Accessory Electric Equipment	127,033,147	4,498,008	295,494	4,793,502	4,471,249	331,237	4,802,486	8,984
346.00 Miscellaneous Power Plant Equipment	1,577,646	61,663	5,564	67,227	53,034	3,911	56,945	(10,282)
Total Solar Units	$ 852,761,375	$ 30,366,400	$ 2,109,370	$ 32,475,770	$ 29,827,617	$ 2,224,406	$ 32,052,023	$ (423,747)
Chino Valley								
341.05 Structures and Improvements	$ 527,890	$ 18,635	$ 1,373	$ 20,008	$ 18,582	$ 1,109	$ 19,691	$ (317)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	77,719,184	2,743,487	202,070	2,945,557	2,735,715	163,210	2,898,925	(46,632)
345.05 Accessory Electric Equipment	6,511,784	229,866	16,931	246,797	229,215	13,675	242,890	(3,907)
346.05 Miscellaneous Power Plant Equipment	216,504	7,643	563	8,206	7,621	455	8,076	(130)
Total Chino Valley	$ 84,975,362	$ 2,999,631	$ 220,937	$ 3,220,568	$ 2,991,133	$ 178,449	$ 3,169,582	$ (50,986)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Cotton Center								
341.05 Structures and Improvements	$ 1,813,499	$ 63,835	$ 4,352	$ 68,187	$ 62,928	$ 3,446	$ 66,374	$ (1,813)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	62,644,922	2,205,101	150,348	2,355,449	2,192,572	119,025	2,311,597	(43,852)
345.05 Accessory Electric Equipment	15,418,007	542,714	37,003	579,717	535,005	29,294	564,299	(15,418)
346.05 Miscellaneous Power Plant Equipment	262,640	9,245	630	9,875	9,114	499	9,613	(262)
Total Cotton Center	$ 80,139,068	$ 2,820,895	$ 192,333	$ 3,013,228	$ 2,799,619	$ 152,264	$ 2,951,883	$ (61,345)
Desert Star								
341.05 Structures and Improvements	$ 1,557,800	$ 70,257	$ 8,101	$ 78,358	$ 45,955	$ 4,518	$ 50,473	$ (27,885)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	29,042,805	1,309,831	151,023	1,460,854	900,327	84,224	984,551	(476,303)
345.05 Accessory Electric Equipment:	4,084,919	184,230	21,242	205,472	120,505	11,846	132,351	(73,121)
346.05 Miscellaneous Power Plant Equipment	291,809	13,161	1,517	14,678	8,608	846	9,454	(5,224)
Total Desert Star	$ 34,977,333	$ 1,577,479	$ 181,883	$ 1,759,362	$ 1,075,395	$ 101,434	$ 1,176,829	$ (582,533)
Foothills Units								
341.05 Structures and Improvements	$ 10,906,684	$ 379,553	$ 32,720	$ 412,273	$ 378,462	$ 25,085	$ 403,547	$ (8,726)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	105,443,248	3,669,425	316,330	3,985,755	3,658,881	242,519	3,901,400	(84,355)
345.05 Accessory Electric Equipment	20,815,540	724,381	62,447	786,828	722,299	47,876	770,175	(16,653)
346.05 Miscellaneous Power Plant Equipment	57,708	2,008	173	2,181	2,002	133	2,135	(46)
Total Foothills Units	$ 137,223,180	$ 4,775,367	$ 411,670	$ 5,187,037	$ 4,761,644	$ 315,613	$ 5,077,257	$ (109,780)
Gila Bend								
341.05 Structures and Improvements	$ 5,018,097	$ 173,626	$ 18,065	$ 191,691	$ 172,121	$ 13,549	$ 185,670	$ (6,021)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	89,246,612	3,087,933	321,288	3,409,221	3,061,159	240,966	3,302,125	(107,096)
345.05 Accessory Electric Equipment	11,096,944	383,954	39,949	423,903	380,625	29,962	410,587	(13,316)
346.05 Miscellaneous Power Plant Equipment	21,142	732	76	808	725	57	782	(26)
Total Gila Bend	$ 105,382,795	$ 3,646,245	$ 379,378	$ 4,025,623	$ 3,614,630	$ 284,534	$ 3,899,164	$ (126,459)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Hyder								
341.05 Structures and Improvements	$ 6,915,232	$ 242,725	$ 11,064	$ 253,789	$ 242,033	$ 8,298	$ 250,331	$ (3,458)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	93,250,197	3,263,757	149,200	3,412,957	3,254,432	111,900	3,366,332	(46,625)
345.05 Accessory Electric Equipment	22,556,482	784,966	36,090	821,056	782,710	27,068	809,778	(11,278)
346.05 Miscellaneous Power Plant Equipment	206,389	7,059	310	7,369	7,017	248	7,265	(104)
Total Hyder	$ 122,928,300	$ 4,298,507	$ 196,664	$ 4,495,171	$ 4,286,192	$ 147,514	$ 4,433,706	$ (61,465)
Legacy								
341.00 Structures and Improvements	$ 313,214	$ 4,103	$ 94	$ 4,197	$ (1,284)	$ 31	$ (1,253)	$ (5,450)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	10,452,105	359,552	8,362	367,914	267,574	1,045	268,619	(99,295)
345.00 Accessory Electric Equipment	1,972,486	83,436	4,339	87,775	63,514	394	63,908	(23,867)
346.00 Miscellaneous Power Plant Equipment								
Total Legacy	$ 12,737,805	$ 447,091	$ 12,795	$ 459,886	$ 329,804	$ 1,470	$ 331,274	$ (128,612)
Luke AFB								
341.05 Structures and Improvements	$ 1,488,329	$ 67,124	$ 8,037	$ 75,161	$ 50,603	$ 5,060	$ 55,663	$ (19,498)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	25,469,888	1,148,692	137,537	1,286,229	865,976	86,598	952,574	(333,655)
345.05 Accessory Electric Equipment	1,757,020	79,242	9,488	88,730	59,739	5,974	65,713	(23,017)
346.05 Miscellaneous Power Plant Equipment	357,678	16,131	1,931	18,062	12,161	1,216	13,377	(4,685)
Total Luke AFB	$ 29,072,915	$ 1,311,189	$ 156,993	$ 1,468,182	$ 988,479	$ 98,848	$ 1,087,327	$ (380,855)
Paloma								
341.05 Structures and Improvements	$ 2,281,950	$ 80,325	$ 6,846	$ 87,171	$ 80,096	$ 5,477	$ 85,573	$ (1,598)
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	49,207,939	1,732,119	147,624	1,879,743	1,732,119	118,099	1,850,218	(29,525)
345.05 Accessory Electric Equipment	12,514,947	440,526	37,545	478,071	439,275	30,036	469,311	(8,760)
346.05 Miscellaneous Power Plant Equipment	121,486	4,276	364	4,640	4,264	292	4,556	(84)
Total Paloma	$ 64,126,322	$ 2,257,246	$ 192,379	$ 2,449,625	$ 2,255,754	$ 153,904	$ 2,409,658	$ (39,967)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Depreciation Accruals - SFAS 143 Method
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique
Accretion Rate: 3.78 Percent

Account Description	12/31/18 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Method Investment	SFAS 143 Method Net Salvage	SFAS 143 Method Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Red Rock								
341.05 Structures and Improvements	$ 4,463,879	$ 148,647	$ -	$ 148,647	$ 160,700	$ 17,409	$ 178,109	$ 29,462
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	72,010,410	2,397,947		2,397,947	2,592,375	280,841	2,873,216	475,269
345.05 Accessory Electric Equipment	13,383,040	445,655		445,655	481,789	52,194	533,983	88,328
346.05 Miscellaneous Power Plant Equipment	42,290	1,408		1,408	1,522	165	1,687	279
Total Redrock	$ 89,899,619	$ 2,993,657	$ -	$ 2,993,657	$ 3,236,386	$ 350,609	$ 3,586,995	$ 593,338
Roof Tops								
341.05 Structures and Improvements	$ 1,585,418	$ 55,965	$ 2,854	$ 58,819	$ 58,660	$ 7,451	$ 66,111	$ 7,292
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	72,791,280	2,584,090	131,024	2,715,114	2,773,348	349,398	3,122,746	407,632
345.05 Accessory Electric Equipment	16,921,978	599,038	30,460	629,498	656,573	82,918	739,491	109,993
346.05 Miscellaneous Power Plant Equipment								
Total Roof Tops	$ 91,298,676	$ 3,239,093	$ 164,338	$ 3,403,431	$ 3,488,581	$ 439,767	$ 3,928,348	$ 524,917

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary - SFAS 143 Method
Vintage Group Procedure
Accretion Rate: 3.78 Percent
December 31, 2018

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
STEAM PRODUCTION										
311.00 Structures and Improvements	$ 141,937,433	$ 70,349,340	49.56%	$ 75,511,986	$ 5,207,210	$ 80,719,196	$ 66,023,737	$ 5,207,210	$ 71,230,947	50.18%
312.00 Boiler Plant Equipment	1,491,411,135	709,065,790	47.54%	573,910,442	45,230,201	619,140,643	647,152,687	45,230,201	692,382,888	46.42%
314.00 Turbogenerator Units	211,425,539	94,840,375	44.86%	96,136,127	7,197,637	103,333,764	97,355,727	7,197,637	104,553,364	49.45%
315.00 Accessory Electric Equipment	117,866,116	56,775,610	48.17%	59,755,058	4,185,503	63,940,560	55,384,095	4,185,503	59,569,598	50.54%
316.00 Miscellaneous Power Plant Equipment	84,425,866	37,830,698	44.81%	36,725,635	2,798,472	39,524,106	38,326,545	2,798,472	41,125,016	48.71%
Total Steam Production Plant	$ 2,047,066,089	$ 968,861,812	47.33%	$ 842,039,247	$ 64,619,022	$ 906,658,269	$ 904,242,790	$ 64,619,022	$ 968,861,812	47.33%
NUCLEAR PRODUCTION										
321.00 Structures and Improvements	$ 850,120,585	$ 432,691,790	50.90%	$ 348,613,063	$ 1,331,517	$ 349,944,580	$ 424,406,707	$ 1,331,517	$ 425,738,224	50.08%
322.00 Reactor Plant Equipment	1,187,263,758	677,764,052	57.09%	522,826,387	5,865,259	528,691,647	672,637,224	5,865,259	678,502,483	57.15%
323.00 Turbogenerator Units	405,048,258	198,640,744	49.04%	159,714,483	610,814	160,325,297	205,412,803	610,814	206,023,617	50.86%
324.00 Accessory Electric Equipment	294,782,526	185,001,401	62.76%	142,371,835	523,592	142,895,427	182,288,207	523,592	182,811,799	62.02%
325.00 Miscellaneous Power Plant Equipment	233,949,471	88,709,442	37.92%	71,956,397	289,733	72,246,129	89,441,572	289,733	89,731,305	38.35%
Total Nuclear Production Plant	$ 2,971,164,598	$ 1,582,807,428	53.27%	$ 1,245,482,165	$ 8,620,914	$ 1,254,103,079	$ 1,574,186,513	$ 8,620,914	$ 1,582,807,428	53.27%
OTHER PRODUCTION										
341.00 Structures and Improvements	$ 131,575,027	$ 35,451,261	26.94%	$ 39,367,098	$ 1,737,379	$ 41,104,477	$ 39,381,422	$ 1,737,379	$ 41,118,800	31.25%
342.00 Fuel Holders, Products and Accessories	56,786,945	26,898,551	47.37%	27,181,155	1,138,882	28,320,037	25,706,687	1,138,882	26,845,569	47.27%
343.00 Prime Movers	655,542,039	269,866,990	41.17%	257,978,040	10,531,433	268,509,473	261,862,014	10,531,433	272,393,447	41.55%
344.00 Generators and Devices	2,104,937,839	369,238,514	17.54%	374,227,730	18,646,287	392,874,016	335,617,302	18,646,287	354,263,589	16.83%
345.00 Accessory Electric Equipment	247,553,984	63,395,509	25.61%	67,825,501	3,338,359	71,163,860	66,536,905	3,338,359	69,875,264	28.23%
346.00 Miscellaneous Power Plant Equipment	34,845,144	9,634,963	27.65%	10,279,384	438,840	10,718,224	9,550,279	438,840	9,989,119	28.67%
Total Other Production Plant	$ 3,231,240,978	$ 774,485,788	23.97%	$ 776,858,908	$ 35,831,179	$ 812,690,087	$ 738,654,609	$ 35,831,179	$ 774,485,788	23.97%
TRANSMISSION PLANT										
352.02 Structures and Improvements	$ 151,995	$ 113,034	74.37%	$ 122,246	$ -	$ 122,246	$ 113,334	$ -	$ 113,334	74.56%
353.00 Station Equipment	132,434,328	30,719,777	23.20%	32,141,863	1,134,089	33,275,952	29,715,846	1,134,089	30,849,934	23.29%
354.00 Towers and Fixtures	1,329,316	623,782	46.93%	663,124		663,124	614,778		614,778	46.25%
355.00 Poles and Fixtures	1,370,085	393,906	28.75%	337,343	44,403	381,745	309,511	44,403	353,914	25.83%
356.00 Overhead Conductors and Devices	1,947,677	734,906	37.73%	631,511	73,321	704,832	580,124	73,321	653,445	33.55%
Total Transmission Plant	$ 137,233,401	$ 32,585,406	23.74%	$ 33,896,087	$ 1,251,813	$ 35,147,899	$ 31,333,593	$ 1,251,813	$ 32,585,406	23.74%
DISTRIBUTION PLANT										
361.00 Structures and Improvements	$ 93,053,192	$ 24,784,504	26.63%	$ 19,608,136	$ 1,085,351	$ 20,693,487	$ 22,904,130	$ 1,085,351	$ 23,989,481	25.78%
362.00 Station Equipment	631,870,595	152,459,460	24.13%	109,146,386	4,919,725	114,066,111	127,314,479	4,919,725	132,234,204	20.93%
363.00 Storage Battery Equipment	13,585,353	(242,468)	-1.78%	1,793,267		1,793,267	2,078,892		2,078,892	15.30%
364.01 Poles, Towers and Fixtures - Wood	357,345,350	94,269,551	26.38%	79,819,683	16,639,687	96,459,371	95,183,429	16,639,687	111,823,117	31.29%
364.02 Poles, Towers and Fixtures - Steel	323,911,866	54,022,644	16.68%	37,197,788	3,229,322	40,427,110	43,636,891	3,229,322	46,866,213	14.47%
365.00 Overhead Conductors and Devices	468,658,341	85,935,082	18.34%	65,047,112	12,349,363	77,396,475	77,374,580	12,349,363	89,723,943	19.14%
366.00 Underground Conduit	727,611,816	208,762,604	28.69%	159,967,954	17,675,017	177,642,972	188,262,370	17,675,017	205,937,387	28.30%
367.00 Underground Conductors and Devices	1,863,851,442	640,622,806	34.37%	454,051,028	60,283,466	514,334,494	535,972,613	60,283,466	596,256,079	31.99%
368.00 Line Transformers	921,018,156	274,977,840	29.86%	208,128,354	8,104,331	216,232,685	242,569,217	8,104,331	250,673,548	27.22%
369.00 Services	447,263,911	141,008,738	31.53%	103,326,433	15,850,965	119,177,397	122,308,635	15,850,965	138,159,599	30.89%
370.01 Meters - Electronic	17,843,353	4,356,437	24.41%	2,386,345		2,386,345	2,766,435		2,766,435	15.50%
370.03 Meters - AMI	302,666,385	47,048,548	15.54%	111,947,890		111,947,890	129,778,598		129,778,598	42.88%
371.00 Installations on Customers' Premises	46,529,246	13,161,123	28.29%	9,250,101	1,400,782	10,650,883	10,946,540	1,400,782	12,347,322	26.54%
373.00 Street Lighting and Signal Systems	80,127,587	25,060,492	31.28%	17,985,726	2,365,360	20,351,086	21,227,184	2,365,360	23,592,543	29.44%
Total Distribution Plant	$ 6,295,336,593	$ 1,766,227,362	28.06%	$ 1,379,656,203	$ 143,903,369	$ 1,523,559,572	$ 1,622,323,993	$ 143,903,369	$ 1,766,227,362	28.06%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary - SFAS 143 Method
Vintage Group Procedure
Accretion Rate: 3.78 Percent
December 31, 2018

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
GENERAL PLANT										
Depreciable										
390.00 Structures and Improvements	$ 265,654,498	$ 33,232,710	12.51%	$ 40,054,780	$ 3,454,595	$ 43,509,375	$ 40,167,285	$ 3,454,595	$ 43,621,880	16.42%
391.CM Office Furn. and Equip. - Computer	243,545,219	113,384,516	46.56%	110,132,581		110,132,581	110,417,359		110,417,359	45.34%
397.00 Communication Equipment	295,372,374	108,507,607	36.74%	102,805,294		102,805,294	103,071,126		103,071,126	34.90%
Total Depreciable	$ 804,572,091	$ 255,124,832	31.71%	$ 252,992,655	$ 3,454,595	$ 256,447,250	$ 253,655,770	$ 3,454,595	$ 257,110,364	31.96%
Amortizable										
391.FE Office Furn. and Equip. - Furniture	$ 63,799,361	$ 34,632,270	54.28%	$ 34,164,558	$ -	$ 34,164,558	$ 34,164,558	$ -	$ 34,164,558	53.55%
393.00 Stores Equipment	594,181	159,335	26.82%	162,806		162,806	162,806		162,806	27.40%
394.00 Tools, Shop and Garage Equipment	43,094,855	21,913,348	50.85%	20,750,173		20,750,173	20,750,173		20,750,173	48.15%
395.00 Laboratory Equipment	767,547	489,181	63.73%	492,765		492,765	492,765		492,765	64.20%
398.00 Miscellaneous Equipment	23,861,303	6,665,059	27.93%	6,303,361		6,303,361	6,303,361		6,303,361	26.42%
Total Amortizable	$ 132,117,247	$ 63,859,194	48.34%	$ 61,873,662	$ -	$ 61,873,662	$ 61,873,662	$ -	$ 61,873,662	46.83%
Total General Plant	$ 936,689,338	$ 318,984,027	34.05%	$ 314,866,317	$ 3,454,595	$ 318,320,912	$ 315,529,432	$ 3,454,595	$ 318,984,027	34.05%
TOTAL UTILITY	$ 15,618,730,997	$ 5,443,951,822	34.86%	$ 4,592,798,927	$ 257,680,891	$ 4,850,479,818	$ 5,186,270,930	$ 257,680,891	$ 5,443,951,822	34.86%
STEAM PRODUCTION (by Unit)				$ 851,152,895						
Cholla										
311.00 Structures and Improvements	$ 78,078,473	$ 38,575,882	49.41%	$ 53,144,547	$ 3,530,265	$ 56,674,812	$ 36,195,621	$ 3,530,265	$ 39,725,885	50.88%
312.00 Boiler Plant Equipment	385,237,434	203,229,153	52.75%	252,309,438	17,570,151	269,879,589	183,016,428	17,570,151	200,586,579	52.07%
314.00 Turbogenerator Units	85,554,772	47,896,982	55.98%	59,037,826	4,087,244	63,125,069	43,901,429	4,087,244	47,988,673	56.09%
315.00 Accessory Electric Equipment	53,298,558	30,464,401	57.16%	39,820,531	2,608,641	42,429,172	28,703,574	2,608,641	31,312,216	58.75%
316.00 Miscellaneous Power Plant Equipment	24,674,267	11,356,450	46.03%	15,436,808	1,068,567	16,505,375	10,840,949	1,068,567	11,909,516	48.27%
Total Cholla	$ 626,843,504	$ 331,522,868	52.89%	$ 419,749,150	$ 28,864,868	$ 448,614,018	$ 302,658,000	$ 28,864,868	$ 331,522,868	52.89%
Cholla Unit 1										
311.00 Structures and Improvements	$ 4,743,207	$ 3,184,960	67.15%	$ 3,464,586	$ 257,841	$ 3,722,427	$ 2,921,750	$ 257,841	$ 3,179,591	67.03%
312.00 Boiler Plant Equipment	82,295,074	50,638,747	61.53%	54,620,245	4,280,645	58,900,889	46,030,818	4,280,645	50,311,463	61.14%
314.00 Turbogenerator Units	27,444,492	16,306,099	59.41%	17,834,450	1,388,248	19,222,698	15,031,233	1,388,248	16,419,481	59.83%
315.00 Accessory Electric Equipment	9,492,908	6,262,264	65.97%	6,839,994	515,585	7,355,579	5,767,341	515,585	6,282,927	66.19%
316.00 Miscellaneous Power Plant Equipment	3,742,187	2,070,672	55.33%	2,467,115	189,587	2,656,703	2,079,692	189,587	2,269,280	60.64%
Total Cholla Unit 1	$ 127,717,868	$ 78,462,742	61.43%	$ 85,226,390	$ 6,631,906	$ 91,858,296	$ 71,830,835	$ 6,631,906	$ 78,462,742	61.43%
Cholla Unit 3										
311.00 Structures and Improvements	$ 13,288,725	$ 6,623,928	49.85%	$ 9,066,445	$ 568,808	$ 9,635,253	$ 6,365,711	$ 568,808	$ 6,934,519	52.18%
312.00 Boiler Plant Equipment	243,068,426	121,796,129	50.11%	157,114,953	10,458,893	167,573,846	110,144,481	10,458,893	120,603,374	49.62%
314.00 Turbogenerator Units	57,062,305	31,015,320	54.35%	40,490,857	2,650,533	43,141,390	28,398,448	2,650,533	31,048,981	54.41%
315.00 Accessory Electric Equipment	34,899,789	20,381,771	58.40%	27,447,712	1,717,742	29,165,454	19,272,718	1,717,742	20,990,461	60.14%
316.00 Miscellaneous Power Plant Equipment	7,009,816	3,213,795	45.85%	4,506,310	292,347	4,798,658	3,161,260	292,347	3,453,608	49.27%
Total Cholla Unit 3	$ 355,329,061	$ 183,030,943	51.51%	$ 238,626,277	$ 15,688,324	$ 254,314,601	$ 167,342,619	$ 15,688,324	$ 183,030,943	51.51%
Cholla Common										
311.00 Structures and Improvements	$ 60,046,541	$ 28,766,995	47.91%	$ 40,613,516	$ 2,703,615	$ 43,317,131	$ 26,908,159	$ 2,703,615	$ 29,611,774	49.31%
312.00 Boiler Plant Equipment	59,873,934	30,794,277	51.43%	40,574,240	2,830,613	43,404,854	26,841,128	2,830,613	29,671,742	49.56%
314.00 Turbogenerator Units	1,047,975	575,563	54.92%	712,519	48,463	760,982	471,747	48,463	520,211	49.64%
315.00 Accessory Electric Equipment	8,905,861	3,820,365	42.90%	5,532,825	375,313	5,908,138	3,663,515	375,313	4,038,828	45.35%
316.00 Miscellaneous Power Plant Equipment	13,922,264	6,071,983	43.61%	8,463,382	586,632	9,050,015	5,599,996	586,632	6,186,628	44.44%
Total Cholla Common	$ 143,796,575	$ 70,029,184	48.70%	$ 95,896,482	$ 6,544,638	$ 102,441,120	$ 63,484,546	$ 6,544,638	$ 70,029,184	48.70%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary - SFAS 143 Method
Vintage Group Procedure
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
Four Corners										
311.00 Structures and Improvements	$ 63,858,960	$ 31,773,458	49.76%	$ 22,367,438	$ 1,676,946	$ 24,044,384	$ 29,828,116	$ 1,676,946	$ 31,505,062	49.34%
312.00 Boiler Plant Equipment	1,106,173,701	505,836,637	45.73%	321,601,004	27,660,049	349,261,054	464,136,259	27,660,049	491,796,308	44.46%
314.00 Turbogenerator Units	125,870,767	46,943,393	37.29%	37,098,302	3,110,393	40,208,694	53,454,298	3,110,393	56,564,691	44.94%
315.00 Accessory Electric Equipment	64,567,558	26,311,209	40.75%	19,934,527	1,576,861	21,511,388	26,680,521	1,576,861	28,257,382	43.76%
316.00 Miscellaneous Power Plant Equipment	59,751,599	26,474,248	44.31%	21,288,827	1,729,905	23,018,731	27,485,596	1,729,905	29,215,501	48.89%
Total Four Corners	$ 1,420,222,585	$ 637,338,944	44.88%	$ 422,290,098	$ 35,754,154	$ 458,044,251	$ 601,584,790	$ 35,754,154	$ 637,338,944	44.88%
Four Corners Units 4-5										
311.00 Structures and Improvements	$ 39,839,762	$ 26,512,392	66.55%	$ 17,471,101	$ 1,365,229	$ 18,836,330	$ 25,585,372	$ 1,365,229	$ 26,950,601	67.65%
312.00 Boiler Plant Equipment	1,066,430,407	493,094,646	46.24%	308,283,734	26,742,229	335,025,962	452,605,444	26,742,229	479,347,672	44.95%
314.00 Turbogenerator Units	121,897,287	45,574,050	37.39%	35,464,336	3,009,581	38,473,917	52,038,041	3,009,581	55,047,622	45.16%
315.00 Accessory Electric Equipment	43,201,151	22,772,976	52.71%	15,679,238	1,300,874	16,980,112	22,993,892	1,300,874	24,294,766	56.24%
316.00 Miscellaneous Power Plant Equipment	39,853,780	21,055,267	52.83%	15,021,910	1,310,935	16,332,845	22,057,735	1,310,935	23,368,670	58.64%
Total Four Corners Units 4-5	$ 1,311,222,387	$ 609,009,331	46.45%	$ 391,920,319	$ 33,728,848	$ 425,649,167	$ 575,280,483	$ 33,728,848	$ 609,009,331	46.45%
Four Corners Common										
311.00 Structures and Improvements	$ 24,019,198	$ 5,261,065	21.90%	$ 4,896,337	$ 311,717	$ 5,208,054	$ 4,242,744	$ 311,717	$ 4,554,461	18.96%
312.00 Boiler Plant Equipment	39,743,294	12,741,991	32.06%	13,317,270	917,821	14,235,091	11,530,815	917,821	12,448,636	31.32%
314.00 Turbogenerator Units	3,973,480	1,369,343	34.46%	1,633,966	100,811	1,734,777	1,416,257	100,811	1,517,069	38.18%
315.00 Accessory Electric Equipment	21,366,407	3,538,233	16.56%	4,255,289	275,987	4,531,276	3,686,629	275,987	3,962,616	18.55%
316.00 Miscellaneous Power Plant Equipment	19,897,819	5,418,980	27.23%	6,266,917	418,970	6,685,886	5,427,861	418,970	5,846,831	29.38%
Total Four Corners Common	$ 109,000,198	$ 28,329,613	25.99%	$ 30,369,779	$ 2,025,306	$ 32,395,085	$ 26,304,307	$ 2,025,306	$ 28,329,613	25.99%
NUCLEAR PRODUCTION (by Unit)										
Palo Verde										
321.00 Structures and Improvements	$ 850,120,585	$ 432,691,790	50.90%	$ 348,613,063	$ 1,331,517	$ 349,944,580	$ 424,406,707	$ 1,331,517	$ 425,738,224	50.08%
322.00 Reactor Plant Equipment	1,187,263,758	677,764,052	57.09%	522,826,387	5,865,259	528,691,647	672,637,224	5,865,259	678,502,483	57.15%
323.00 Turbogenerator Units	405,048,258	198,640,744	49.04%	159,714,483	610,814	160,325,297	205,412,803	610,814	206,023,617	50.86%
324.00 Accessory Electric Equipment	294,782,526	185,001,401	62.76%	142,371,835	523,592	142,895,427	182,288,207	523,592	182,811,799	62.02%
325.00 Miscellaneous Power Plant Equipment	233,949,471	88,709,442	37.92%	71,956,397	289,733	72,246,129	89,441,572	289,733	89,731,305	38.35%
Total Palo Verde	$ 2,971,164,598	$ 1,582,807,428	53.27%	$ 1,245,482,165	$ 8,620,914	$ 1,254,103,079	$ 1,574,186,513	$ 8,620,914	$ 1,582,807,428	53.27%
Palo Verde Unit 1										
321.00 Structures and Improvements	$ 169,287,979	$ 113,114,947	66.82%	$ 85,996,670	$ 298,909	$ 86,295,579	$ 111,115,573	$ 298,909	$ 111,414,482	65.81%
322.00 Reactor Plant Equipment	465,986,593	287,237,408	61.64%	220,431,399	2,334,601	222,766,000	285,274,089	2,334,601	287,608,690	61.72%
323.00 Turbogenerator Units	144,321,116	74,895,472	51.90%	60,034,027	216,202	60,250,229	77,571,653	216,202	77,787,855	53.90%
324.00 Accessory Electric Equipment	121,319,415	82,787,025	68.24%	62,867,673	218,479	63,086,152	81,230,780	218,479	81,449,259	67.14%
325.00 Miscellaneous Power Plant Equipment	33,599,919	20,834,661	62.01%	15,905,542	57,240	15,962,782	20,551,986	57,240	20,609,226	61.34%
Total Palo Verde Unit 1	$ 934,515,022	$ 578,869,513	61.94%	$ 445,235,311	$ 3,125,432	$ 448,360,743	$ 575,744,081	$ 3,125,432	$ 578,869,513	61.94%
Palo Verde Unit 2										
321.00 Structures and Improvements	$ 94,477,904	$ 62,447,235	66.10%	$ 48,647,062	$ 175,393	$ 48,822,455	$ 61,333,594	$ 175,393	$ 61,508,987	65.10%
322.00 Reactor Plant Equipment	248,880,636	139,105,347	55.89%	108,335,630	1,210,629	109,546,259	136,801,263	1,210,629	138,011,892	55.45%
323.00 Turbogenerator Units	87,819,612	42,490,094	48.38%	35,500,239	133,633	35,633,872	44,759,713	133,633	44,893,346	51.12%
324.00 Accessory Electric Equipment	49,752,711	31,501,138	63.32%	24,739,350	89,885	24,829,234	31,191,235	89,885	31,281,119	62.87%
325.00 Miscellaneous Power Plant Equipment	27,865,592	16,921,154	60.72%	13,261,439	49,367	13,310,806	16,720,257	49,367	16,769,624	60.18%
Total Palo Verde Unit 2	$ 508,796,455	$ 292,464,968	57.48%	$ 230,483,720	$ 1,658,907	$ 232,142,627	$ 290,806,061	$ 1,658,907	$ 292,464,968	57.48%

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
Palo Verde Unit 3										
321.00 Structures and Improvements	$ 167,896,725	$ 107,517,902	64.04%	$ 81,359,507	$ 316,991	$ 81,676,498	$ 105,499,107	$ 316,991	$ 105,816,097	63.02%
322.00 Reactor Plant Equipment	436,634,437	236,799,254	54.23%	180,553,988	2,158,547	182,712,535	234,554,924	2,158,547	236,713,471	54.21%
323.00 Turbogenerator Units	167,364,071	80,085,013	47.85%	63,027,788	256,040	63,283,827	81,731,408	256,040	81,987,448	48.99%
324.00 Accessory Electric Equipment	95,765,260	57,960,208	60.54%	44,537,200	174,264	44,711,464	57,751,734	174,264	57,925,998	60.49%
325.00 Miscellaneous Power Plant Equipment	29,878,581	17,348,950	58.06%	13,290,796	53,570	13,344,367	17,234,742	53,570	17,288,312	57.86%
Total Palo Verde Unit 3	$ 897,539,074	$ 499,731,327	55.68%	$ 382,769,279	$ 2,959,412	$ 385,728,691	$ 496,771,915	$ 2,959,412	$ 499,731,327	55.68%
Palo Verde Water Reclamation										
321.00 Structures and Improvements	$ 233,902,104	$ 74,873,790	32.01%	$ 71,601,478	$ 294,404	$ 71,895,882	$ 74,194,658	$ 294,404	$ 74,489,063	31.85%
322.00 Reactor Plant Equipment	454,911	(315,403)	-69.33%	64,886	805	65,691	67,255	805	68,061	14.96%
323.00 Turbogenerator Units	217,756	104,964	48.20%	101,611	412	102,023	105,291	412	105,703	48.54%
324.00 Accessory Electric Equipment										
325.00 Miscellaneous Power Plant Equipment	241,107	56,987	23.64%	55,286	224	55,511	57,288	224	57,513	23.85%
Total Palo Verde Water Reclamation	$ 234,815,878	$ 74,720,339	31.82%	$ 71,823,261	$ 295,846	$ 72,119,108	$ 74,424,493	$ 295,846	$ 74,720,339	31.82%
Palo Verde Common										
321.00 Structures and Improvements	$ 184,555,873	$ 74,737,915	40.50%	$ 61,008,345	$ 245,820	$ 61,254,165	$ 72,263,776	$ 245,820	$ 72,509,596	39.29%
322.00 Reactor Plant Equipment	35,307,181	14,937,445	42.31%	13,440,485	160,676	13,601,161	15,939,693	160,676	16,100,370	45.60%
323.00 Turbogenerator Units	5,325,703	1,065,201	20.00%	1,050,818	4,527	1,055,345	1,244,738	4,527	1,249,265	23.46%
324.00 Accessory Electric Equipment	27,945,140	12,733,029	45.56%	10,227,611	40,964	10,268,575	12,114,458	40,964	12,155,422	43.50%
325.00 Miscellaneous Power Plant Equipment	142,364,272	33,547,691	23.56%	29,443,333	129,331	29,572,664	34,877,299	129,331	35,006,630	24.59%
Total Palo Verde Common	$ 395,498,169	$ 137,021,281	34.65%	$ 115,170,593	$ 581,318	$ 115,751,910	$ 136,439,964	$ 581,318	$ 137,021,281	34.65%
OTHER PRODUCTION										
Combined Cycle										
341.00 Structures and Improvements	$ 63,600,586	$ 18,701,434	29.40%	$ 21,856,967	$ 870,221	$ 22,727,188	$ 21,105,095	$ 870,221	$ 21,975,316	34.55%
342.00 Fuel Holders, Products and Accessories	41,829,313	18,054,578	43.16%	18,912,990	805,775	19,718,765	18,000,112	805,775	18,805,887	44.96%
343.00 Prime Movers	274,702,584	95,474,865	34.76%	112,822,488	4,723,791	117,546,279	94,375,767	4,723,791	99,099,559	36.08%
344.00 Generators and Devices	727,795,468	201,653,014	27.71%	207,883,687	8,948,393	216,832,080	179,785,129	8,948,393	188,733,522	25.93%
345.00 Accessory Electric Equipment	78,442,697	20,068,505	25.58%	26,612,739	1,118,213	27,730,952	23,630,217	1,118,213	24,748,430	31.55%
346.00 Miscellaneous Power Plant Equipment	20,741,997	5,209,055	25.11%	6,096,289	261,207	6,357,496	5,537,529	261,207	5,798,736	27.96%
Total Combined Cycle	$ 1,207,112,645	$ 359,161,451	29.75%	$ 394,185,160	$ 16,727,601	$ 410,912,761	$ 342,433,850	$ 16,727,601	$ 359,161,451	29.75%
Redhawk CC Units 1-2										
341.00 Structures and Improvements	$ 23,988,173	$ 6,434,553	26.82%	$ 9,474,726	$ 390,783	$ 9,865,509	$ 7,597,541	$ 390,783	$ 7,988,324	33.30%
342.00 Fuel Holders, Products and Accessories	12,809,613	1,858,155	14.51%	3,144,907	129,522	3,274,429	2,521,857	129,522	2,651,379	20.70%
343.00 Prime Movers	132,414,998	36,154,393	27.30%	52,665,558	2,270,891	54,936,449	42,212,385	2,270,891	44,483,277	33.59%
344.00 Generators and Devices	391,212,295	90,340,613	23.09%	91,581,504	4,076,771	95,658,275	73,379,882	4,076,771	77,456,653	19.80%
345.00 Accessory Electric Equipment	29,897,838	6,334,454	21.19%	10,046,553	412,689	10,459,242	8,056,394	412,689	8,469,083	28.33%
346.00 Miscellaneous Power Plant Equipment	6,872,469	1,400,145	20.37%	1,747,190	72,690	1,819,880	1,400,908	72,690	1,473,597	21.44%
Total Redhawk CC Units 1-2	$ 597,195,386	$ 142,522,314	23.87%	$ 168,660,438	$ 7,353,347	$ 176,013,784	$ 135,168,967	$ 7,353,347	$ 142,522,314	23.87%
West Phoenix										
341.00 Structures and Improvements	$ 39,612,413	$ 12,266,881	30.97%	$ 12,382,242	$ 479,437	$ 12,861,679	$ 13,507,554	$ 479,437	$ 13,986,992	35.31%
342.00 Fuel Holders, Products and Accessories	29,019,700	16,196,423	55.81%	15,768,083	676,253	16,444,336	15,478,255	676,253	16,154,508	55.67%
343.00 Prime Movers	142,287,586	59,320,471	41.69%	60,156,930	2,452,900	62,609,830	52,163,382	2,452,900	54,616,282	38.38%
344.00 Generators and Devices	336,583,173	111,312,401	33.07%	116,302,182	4,871,623	121,173,805	106,405,247	4,871,623	111,276,869	33.06%
345.00 Accessory Electric Equipment	48,544,859	13,734,051	28.29%	16,566,186	705,524	17,271,710	15,573,823	705,524	16,279,347	33.53%
346.00 Miscellaneous Power Plant Equipment	13,869,528	3,808,910	27.46%	4,349,099	188,517	4,537,617	4,136,622	188,517	4,325,139	31.18%
Total West Phoenix	$ 609,917,259	$ 216,639,138	35.52%	$ 225,524,722	$ 9,374,254	$ 234,898,977	$ 207,264,883	$ 9,374,254	$ 216,639,138	35.52%

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A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
West Phoenix CC Units 1-3										
341.00 Structures and Improvements	$ 366,217	$ (174,165)	-47.56%	$ 192,172	$ 8,455	$ 200,627	$ 192,093	$ 8,455	$ 200,548	54.76%
342.00 Fuel Holders, Products and Accessories	22,031,967	14,160,758	64.27%	12,714,230	550,970	13,265,200	12,709,024	550,970	13,259,994	60.19%
343.00 Prime Movers										
344.00 Generators and Devices	130,345,213	61,299,140	47.03%	57,090,686	2,498,798	59,589,484	57,067,303	2,498,798	59,566,101	45.70%
345.00 Accessory Electric Equipment	32,620,455	9,777,883	29.97%	11,170,092	495,387	11,665,479	11,165,514	495,387	11,660,902	35.75%
346.00 Miscellaneous Power Plant Equipment	8,073,969	2,842,783	35.21%	3,083,349	136,768	3,220,117	3,082,085	136,768	3,218,853	39.87%
Total West Phoenix CC Units 1-3	$ 193,437,821	$ 87,906,399	45.44%	$ 84,250,528	$ 3,690,379	$ 87,940,907	$ 84,216,020	$ 3,690,379	$ 87,906,399	45.44%
West Phoenix CC Unit 4										
341.00 Structures and Improvements	$ 7,035,987	$ 2,018,949	28.69%	$ 2,288,915	$ 90,285	$ 2,379,201	$ 2,170,426	$ 90,285	$ 2,260,711	32.13%
342.00 Fuel Holders, Products and Accessories	4,470,010	2,035,665	45.54%	2,125,312	83,654	2,208,966	2,015,300	83,654	2,098,954	46.96%
343.00 Prime Movers	49,464,010	24,639,897	49.81%	24,200,134	957,357	25,157,491	22,947,234	957,357	23,904,591	48.33%
344.00 Generators and Devices	23,956,815	8,472,007	35.36%	8,936,621	361,129	9,297,750	8,473,572	361,129	8,834,701	36.88%
345.00 Accessory Electric Equipment	552,377	143,454	25.97%	156,599	6,414	163,013	148,481	6,414	154,895	28.04%
346.00 Miscellaneous Power Plant Equipment	942,600	132,993	14.11%	191,068	7,958	199,026	181,156	7,958	189,114	20.06%
Total West Phoenix CC Unit 4	$ 86,421,799	$ 37,442,966	43.33%	$ 37,898,648	$ 1,506,798	$ 39,405,446	$ 35,936,168	$ 1,506,798	$ 37,442,966	43.33%
West Phoenix CC Unit 5										
341.00 Structures and Improvements	$ 11,054,705	$ 2,517,789	22.78%	$ 4,251,534	$ 164,726	$ 4,416,260	$ 3,456,699	$ 164,726	$ 3,621,424	32.76%
342.00 Fuel Holders, Products and Accessories	2,517,723			928,542	41,629	970,171	753,931	41,629	795,560	31.60%
343.00 Prime Movers	92,823,576	34,680,574	37.36%	35,956,796	1,495,543	37,452,339	29,216,148	1,495,543	30,711,691	33.09%
344.00 Generators and Devices	182,281,145	41,541,253	22.79%	50,274,876	2,011,695	52,286,571	40,864,372	2,011,695	42,876,067	23.52%
345.00 Accessory Electric Equipment	15,372,027	3,812,715	24.80%	5,239,495	203,723	5,443,217	4,259,828	203,723	4,463,550	29.04%
346.00 Miscellaneous Power Plant Equipment	4,852,959	833,134	17.17%	1,074,683	43,791	1,118,474	873,381	43,791	917,172	18.90%
Total West Phoenix CC Unit 5	$ 308,902,135	$ 83,385,465	26.99%	$ 97,725,926	$ 3,961,107	$ 101,687,032	$ 79,424,358	$ 3,961,107	$ 83,385,465	26.99%
West Phoenix Common										
341.00 Structures and Improvements	$ 21,155,504	$ 7,904,308	37.36%	$ 5,649,620	$ 215,971	$ 5,865,591	$ 7,688,337	$ 215,971	$ 7,904,308	37.36%
342.00 Fuel Holders, Products and Accessories										
343.00 Prime Movers										
344.00 Generators and Devices										
345.00 Accessory Electric Equipment										
346.00 Miscellaneous Power Plant Equipment										
Total West Phoenix Common	$ 21,155,504	$ 7,904,308	37.36%	$ 5,649,620	$ 215,971	$ 5,865,591	$ 7,688,337	$ 215,971	$ 7,904,308	37.36%
Combustion Turbine										
341.00 Structures and Improvements	$ 31,102,449	$ 10,228,622	32.89%	$ 11,069,663	$ 464,931	$ 11,534,594	$ 11,760,381	$ 464,931	$ 12,225,313	39.31%
342.00 Fuel Holders, Products and Accessories	14,957,632	8,843,973	59.13%	8,268,165	333,106	8,601,272	7,706,575	333,106	8,039,681	53.75%
343.00 Prime Movers	380,839,455	174,392,126	45.79%	145,155,552	5,807,642	150,963,194	167,486,247	5,807,642	173,293,888	45.50%
344.00 Generators and Devices	689,863,781	37,302,414	5.41%	44,514,302	1,706,037	46,220,340	35,411,264	1,706,037	37,117,301	5.38%
345.00 Accessory Electric Equipment	42,078,140	20,677,181	49.14%	18,058,067	731,392	18,789,458	20,314,755	731,392	21,046,146	50.02%
346.00 Miscellaneous Power Plant Equipment	12,525,501	4,137,658	33.03%	3,905,013	160,616	4,065,629	3,699,028	160,616	3,859,644	30.81%
Total Combustion Turbine	$ 1,171,366,958	$ 255,581,974	21.82%	$ 230,970,762	$ 9,203,724	$ 240,174,486	$ 246,378,249	$ 9,203,724	$ 255,581,974	21.82%

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Depreciation Reserve Summary - SFAS 143 Method
Vintage Group Procedure
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Ratio
A	B	C	D=CB	E	F	G=E+F	H	I	J=H+I	K=JB
Douglas CT										
341.00 Structures and Improvements	$ 103,952	$ (109,082)	-104.94%	$ 50,635	$ 2,225	$ 52,860	$ (3,791)	$ 2,225	$ (1,566)	-1.51%
342.00 Fuel Holders, Products and Accessories	137,759	(301,173)	-218.62%	100,691	4,149	104,840	(7,255)	4,149	(3,106)	-2.25%
343.00 Prime Movers	3,721,569	2,728,550	73.32%	1,262,946	55,483	1,318,430	(94,548)	55,483	(39,065)	-1.05%
344.00 Generators and Devices	971,924	(1,480,347)	-152.31%	558,098	22,756	580,855	(39,967)	22,756	(17,210)	-1.77%
345.00 Accessory Electric Equipment	582,402	(834,397)	-143.27%	304,683	12,498	317,181	(21,896)	12,498	(9,398)	-1.61%
346.00 Miscellaneous Power Plant Equipment	33,564	(74,654)	-222.42%	24,537	1,007	25,544	(1,764)	1,007	(757)	-2.26%
Total Douglas CT	$ 5,551,170	$ (71,102)	-1.28%	$ 2,301,591	$ 98,119	$ 2,399,710	$ (169,221)	$ 98,119	$ (71,102)	-1.28%
Ocotillo										
341.00 Structures and Improvements	$ 3,189,602	$ 65,746	2.06%	$ 900,926	$ 40,163	$ 941,089	$ 614,725	$ 40,163	$ 654,888	20.53%
342.00 Fuel Holders, Products and Accessories	1,484,432	581,896	39.20%	732,258	31,089	763,347	500,111	31,089	531,200	35.78%
343.00 Prime Movers	24,161,626	6,082,793	25.18%	9,324,161	408,722	9,732,884	6,364,225	408,722	6,772,948	28.03%
344.00 Generators and Devices	612,033,648	8,902,408	1.45%	15,456,097	511,001	15,967,098	7,384,894	511,001	7,895,895	1.29%
345.00 Accessory Electric Equipment	4,017,658	1,504,914	37.46%	1,923,819	82,156	2,005,974	1,313,768	82,156	1,395,923	34.74%
346.00 Miscellaneous Power Plant Equipment	950,460	510,095	53.67%	547,590	22,905	570,495	374,093	22,905	396,998	41.77%
Total Ocotillo	$ 645,837,426	$ 17,647,852	2.73%	$ 28,884,852	$ 1,096,036	$ 29,980,887	$ 16,551,816	$ 1,096,036	$ 17,647,852	2.73%
Ocotillo CT Units 1-2										
341.00 Structures and Improvements	$ 3,189,602	$ 65,746	2.06%	$ 900,926	$ 40,163	$ 941,089	$ 614,725	$ 40,163	$ 654,888	20.53%
342.00 Fuel Holders, Products and Accessories	1,484,432	581,896	39.20%	732,258	31,089	763,347	500,111	31,089	531,200	35.78%
343.00 Prime Movers	24,161,626	6,082,793	25.18%	9,324,161	408,722	9,732,884	6,364,225	408,722	6,772,948	28.03%
344.00 Generators and Devices	15,486,821	5,931,627	38.30%	6,783,166	294,337	7,077,503	4,630,777	294,337	4,925,114	31.80%
345.00 Accessory Electric Equipment	4,017,658	1,504,914	37.46%	1,923,819	82,156	2,005,974	1,313,768	82,156	1,395,923	34.74%
346.00 Miscellaneous Power Plant Equipment	950,460	510,095	53.67%	547,590	22,905	570,495	374,093	22,905	396,998	41.77%
Total Octillo CT Units 1-2	$ 49,290,599	$ 14,677,070	29.78%	$ 20,211,920	$ 879,372	$ 21,091,292	$ 13,797,699	$ 879,372	$ 14,677,070	29.78%
Ocotillo CT Units 3-7										
341.00 Structures and Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	
342.00 Fuel Holders, Products and Accessories										
343.00 Prime Movers										
344.00 Generators and Devices	596,546,827	2,970,782	0.50%	8,672,931	216,664	8,889,595	2,754,118	216,664	2,970,782	0.50%
345.00 Accessory Electric Equipment										
346.00 Miscellaneous Power Plant Equipment										
Total Octillo CT Units 3-7	$ 596,546,827	$ 2,970,782	0.50%	$ 8,672,931	$ 216,664	$ 8,889,595	$ 2,754,118	$ 216,664	$ 2,970,782	0.50%
Saguaro										
341.00 Structures and Improvements	$ 3,051,365	$ 1,442,471	47.27%	$ 1,397,204	$ 61,023	$ 1,458,227	$ 1,186,250	$ 61,023	$ 1,247,273	40.88%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,271,253	77.40%	1,109,738	45,749	1,155,487	942,580	45,749	988,329	60.17%
343.00 Prime Movers	23,292,483	5,718,981	24.55%	7,819,384	332,299	8,151,683	6,802,554	332,299	7,134,854	30.63%
344.00 Generators and Devices	38,498,152	17,877,019	46.44%	15,490,760	622,599	16,113,359	16,429,755	622,599	17,052,355	44.29%
345.00 Accessory Electric Equipment	3,593,189	1,454,205	40.47%	1,625,188	68,431	1,693,619	1,403,964	68,431	1,472,394	40.98%
346.00 Miscellaneous Power Plant Equipment	916,172	662,539	72.32%	596,288	24,831	621,119	506,434	24,831	531,265	57.99%
Total Saguaro	$ 70,993,849	$ 28,426,468	40.04%	$ 28,038,563	$ 1,154,931	$ 29,193,494	$ 27,271,537	$ 1,154,931	$ 28,426,468	40.04%

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
Saguaro CT Units 1-2										
341.00 Structures and Improvements	$ 3,051,365	$ 1,442,471	47.27%	$ 1,397,204	$ 61,023	$ 1,458,227	$ 1,186,250	$ 61,023	$ 1,247,273	40.88%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,271,253	77.40%	1,109,738	45,749	1,155,487	942,580	45,749	988,329	60.17%
343.00 Prime Movers	21,353,178	5,183,748	24.28%	7,271,018	310,352	7,581,370	6,174,259	310,352	6,484,611	30.37%
344.00 Generators and Devices	14,724,431	4,647,555	31.56%	4,439,116	192,972	4,632,088	3,769,015	192,972	3,961,987	26.91%
345.00 Accessory Electric Equipment	3,269,324	1,383,086	42.30%	1,544,862	65,253	1,610,115	1,311,935	65,253	1,377,188	42.12%
346.00 Miscellaneous Power Plant Equipment	916,172	662,539	72.32%	596,288	24,831	621,119	506,434	24,831	531,265	57.99%
Total Saguaro CT Units 1-2	$ 44,956,958	$ 14,590,652	32.45%	$ 16,358,227	$ 700,179	$ 17,058,406	$ 13,890,473	$ 700,179	$ 14,590,652	32.45%
Saguaro CT Unit 3										
341.00 Structures and Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	
342.00 Fuel Holders, Products and Accessories										
343.00 Prime Movers	1,939,305	535,233	27.60%	548,366	21,948	570,313	628,295	21,948	650,243	33.53%
344.00 Generators and Devices	23,773,721	13,229,464	55.65%	11,051,644	429,627	11,481,271	12,660,740	429,627	13,090,367	55.06%
345.00 Accessory Electric Equipment	323,865	71,120	21.96%	80,326	3,177	83,503	92,029	3,177	95,206	29.40%
346.00 Miscellaneous Power Plant Equipment										
Total Saguaro CT Unit 3	$ 26,036,891	$ 13,835,816	53.14%	$ 11,680,336	$ 454,752	$ 12,135,088	$ 13,381,064	$ 454,752	$ 13,835,816	53.14%
Sundance Units 1-10										
341.00 Structures and Improvements	$ 13,762,067	$ 6,860,041	49.85%	$ 5,129,107	$ 205,190	$ 5,334,297	$ 6,993,976	$ 205,190	$ 7,199,166	52.31%
342.00 Fuel Holders, Products and Accessories	4,418,231	2,391,416	54.13%	1,730,685	68,792	1,799,477	2,359,781	68,792	2,428,574	54.97%
343.00 Prime Movers	227,932,672	129,018,866	56.60%	90,991,087	3,610,014	94,601,101	124,063,612	3,610,014	127,673,626	56.01%
344.00 Generators and Devices	13,058,506	1,972,219	15.10%	2,184,441	90,801	2,275,242	2,979,866	90,801	3,070,667	23.51%
345.00 Accessory Electric Equipment	27,804,255	15,482,562	55.68%	10,816,946	428,946	11,245,892	14,748,508	428,946	15,177,454	54.59%
346.00 Miscellaneous Power Plant Equipment	6,970,933	1,296,100	18.59%	1,048,753	41,731	1,090,485	1,429,987	41,731	1,471,718	21.11%
Total Sun Dance Units 1-10	$ 293,946,664	$ 157,021,204	53.42%	$ 111,901,019	$ 4,445,475	$ 116,346,494	$ 152,575,729	$ 4,445,475	$ 157,021,204	53.42%
West Phoenix CT Units 1-2										
341.00 Structures and Improvements	$ 4,239,486	$ 1,109,653	26.17%	$ 1,303,461	$ 57,769	$ 1,361,230	$ 892,554	$ 57,769	$ 950,323	22.42%
342.00 Fuel Holders, Products and Accessories	1,843,219	1,100,840	59.72%	1,168,900	47,819	1,216,718	801,616	47,819	849,435	46.08%
343.00 Prime Movers	20,466,623	5,881,051	28.73%	9,182,592	397,332	9,579,924	6,290,756	397,332	6,688,088	32.68%
344.00 Generators and Devices	15,280,205	4,269,530	27.94%	5,261,413	226,077	5,487,491	3,604,936	226,077	3,831,014	25.07%
345.00 Accessory Electric Equipment	1,525,954	463,354	30.36%	922,075	38,174	960,249	632,210	38,174	670,384	43.93%
346.00 Miscellaneous Power Plant Equipment	1,026,473	628,767	61.26%	637,512	27,044	664,556	436,906	27,044	463,950	45.20%
Total West Phoenix CT Units 1-2	$ 44,381,960	$ 13,453,194	30.31%	$ 18,475,952	$ 794,216	$ 19,270,168	$ 12,658,978	$ 794,216	$ 13,453,194	30.31%
Yucca										
341.00 Structures and Improvements	$ 6,755,977	$ 859,793	12.73%	$ 2,288,330	$ 98,561	$ 2,386,891	$ 2,076,668	$ 98,561	$ 2,175,229	32.20%
342.00 Fuel Holders, Products and Accessories	5,431,503	3,799,741	69.96%	3,425,893	135,508	3,561,402	3,109,742	135,508	3,245,251	59.75%
343.00 Prime Movers	81,264,482	24,961,885	30.72%	26,575,382	1,003,791	27,579,172	24,059,647	1,003,791	25,063,438	30.84%
344.00 Generators and Devices	10,021,346	5,761,585	57.49%	5,563,492	232,803	5,796,295	5,051,779	232,803	5,284,582	52.73%
345.00 Accessory Electric Equipment	4,554,682	2,606,543	57.23%	2,465,356	101,187	2,566,543	2,238,201	101,187	2,339,388	51.36%
346.00 Miscellaneous Power Plant Equipment	2,627,899	1,114,812	42.42%	1,050,332	43,098	1,093,430	953,372	43,098	996,471	37.92%
Total Yucca	$ 110,655,889	$ 39,104,358	35.34%	$ 41,368,786	$ 1,614,948	$ 42,983,733	$ 37,489,411	$ 1,614,948	$ 39,104,358	35.34%

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A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
Yucca CT Units 1-4										
341.00 Structures and Improvements	$ 5,685,548	$ 616,237	10.84%	$ 2,050,263	$ 89,739	$ 2,140,002	$ 1,861,391	$ 89,739	$ 1,951,130	34.32%
342.00 Fuel Holders, Products and Accessories	3,934,860	3,357,198	85.32%	2,990,360	119,538	3,109,898	2,715,888	119,538	2,835,426	72.06%
343.00 Prime Movers	12,670,962	6,731,737	53.13%	7,142,968	291,861	7,434,829	6,486,788	291,861	6,778,649	53.50%
344.00 Generators and Devices	9,848,867	5,727,556	58.15%	5,528,787	231,515	5,760,302	5,020,397	231,515	5,251,912	53.33%
345.00 Accessory Electric Equipment	3,737,069	2,473,783	66.20%	2,313,842	95,318	2,409,160	2,101,216	95,318	2,196,534	58.78%
346.00 Miscellaneous Power Plant Equipment	1,536,718	1,001,468	65.17%	941,876	39,022	980,898	855,305	39,022	894,327	58.20%
Total Yucca CT Units 1-4	$ 37,414,024	$ 19,907,978	53.21%	$ 20,968,097	$ 866,993	$ 21,835,090	$ 19,040,985	$ 866,993	$ 19,907,978	53.21%
Yucca CT Units 5-6										
341.00 Structures and Improvements	$ 1,070,429	$ 243,556	22.75%	$ 238,068	$ 8,821	$ 246,889	$ 215,277	$ 8,821	$ 224,099	20.94%
342.00 Fuel Holders, Products and Accessories	1,496,643	442,543	29.57%	435,533	15,970	451,503	393,854	15,970	409,824	27.38%
343.00 Prime Movers	68,593,520	18,230,148	26.58%	19,432,414	711,930	20,144,343	17,572,859	711,930	18,284,789	26.66%
344.00 Generators and Devices	172,479	34,030	19.73%	34,705	1,288	35,993	31,382	1,288	32,670	18.94%
345.00 Accessory Electric Equipment	817,613	132,760	16.24%	151,514	5,869	157,383	136,985	5,869	142,855	17.47%
346.00 Miscellaneous Power Plant Equipment	1,091,181	113,344	10.39%	108,456	4,076	112,532	98,068	4,076	102,144	9.36%
Total Yucca CT Units 5-6	$ 73,241,865	$ 19,196,381	26.21%	$ 20,400,689	$ 747,955	$ 21,148,644	$ 18,448,426	$ 747,955	$ 19,196,381	26.21%
Solar Units										
341.00 Structures and Improvements	$ 36,871,992	$ 6,521,205	17.69%	$ 6,440,469	$ 402,227	$ 6,842,695	$ 6,515,945	$ 402,227	$ 6,918,171	18.76%
342.00 Fuel Holders, Products and Accessories										
343.00 Prime Movers										
344.00 Generators and Devices	687,278,590	130,283,085	18.96%	121,829,741	7,991,856	129,821,597	120,420,910	7,991,856	128,412,765	18.68%
345.00 Accessory Electric Equipment	127,033,147	22,649,823	17.83%	23,154,695	1,488,754	24,643,449	22,591,934	1,488,754	24,080,688	18.96%
346.00 Miscellaneous Power Plant Equipment	1,577,646	288,249	18.27%	278,082	17,016	295,098	313,722	17,016	330,738	20.96%
Total Solar Units	$ 852,761,375	$ 159,742,363	18.73%	$ 151,702,986	$ 9,899,853	$ 161,602,840	$ 149,842,510	$ 9,899,853	$ 159,742,363	18.73%
Chino Valley										
341.05 Structures and Improvements	$ 527,890	$ 110,183	20.87%	$ 111,855	$ 6,200	$ 118,055	$ 103,982	$ 6,200	$ 110,182	20.87%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	77,719,184	16,221,704	20.87%	16,467,978	912,870	17,380,848	15,308,834	912,870	16,221,704	20.87%
345.05 Accessory Electric Equipment	6,511,784	1,359,153	20.87%	1,379,787	76,486	1,456,273	1,282,667	76,486	1,359,153	20.87%
346.05 Miscellaneous Power Plant Equipment	216,504	45,189	20.87%	45,875	2,543	48,418	42,646	2,543	45,189	20.87%
Total Chino Valley	$ 84,975,362	$ 17,736,228	20.87%	$ 18,005,495	$ 998,100	$ 19,003,595	$ 16,738,129	$ 998,100	$ 17,736,228	20.87%
Cotton Center										
341.05 Structures and Improvements	$ 1,813,499	$ 442,322	24.39%	$ 444,135	$ 23,216	$ 467,351	$ 437,052	$ 23,216	$ 460,268	25.38%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	62,644,922	15,731,380	25.11%	15,012,992	784,700	15,797,691	14,773,567	784,700	15,558,266	24.84%
345.05 Accessory Electric Equipment	15,418,007	3,760,538	24.39%	3,775,947	197,378	3,973,326	3,715,729	197,378	3,913,107	25.38%
346.05 Miscellaneous Power Plant Equipment	262,640	64,060	24.39%	64,322	3,362	67,684	63,296	3,362	66,658	25.38%
Total Cotton Center	$ 80,139,068	$ 19,998,300	24.95%	$ 19,297,396	$ 1,008,656	$ 20,306,052	$ 18,989,643	$ 1,008,656	$ 19,998,300	24.95%

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December 31, 2018

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
Desert Star										
341.05 Structures and Improvements	$ 1,557,800	$ 202,535	13.00%	$ 176,863	$ 13,750	$ 190,613	$ 382,035	$ 13,750	$ 395,785	25.41%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	29,042,805	6,928,587	23.86%	2,759,631	214,786	2,974,416	5,961,230	214,786	6,176,016	21.27%
345.05 Accessory Electric Equipment	4,084,919	514,847	12.60%	463,778	36,055	499,832	1,001,787	36,055	1,037,841	25.41%
346.05 Miscellaneous Power Plant Equipment	291,809	37,812	12.96%	33,130	2,576	35,706	71,563	2,576	74,139	25.41%
Total Desert Star	$ 34,977,333	$ 7,683,781	21.97%	$ 3,433,402	$ 267,166	$ 3,700,568	$ 7,416,615	$ 267,166	$ 7,683,781	21.97%
Foothills Units										
341.05 Structures and Improvements	$ 10,906,684	$ 2,002,258	18.36%	$ 1,950,452	$ 123,465	$ 2,073,917	$ 1,917,165	$ 123,465	$ 2,040,630	18.71%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	105,443,248	19,840,062	18.82%	18,856,506	1,193,615	20,050,121	18,534,697	1,193,615	19,728,312	18.71%
345.05 Accessory Electric Equipment	20,815,540	3,821,391	18.36%	3,722,461	235,634	3,958,095	3,658,932	235,634	3,894,567	18.71%
346.05 Miscellaneous Power Plant Equipment	57,708	10,594	18.36%	10,320	653	10,973	10,144	653	10,797	18.71%
Total Foothills Units	$ 137,223,180	$ 25,674,305	18.71%	$ 24,539,739	$ 1,553,368	$ 26,093,106	$ 24,120,938	$ 1,553,368	$ 25,674,305	18.71%
Gila Bend										
341.05 Structures and Improvements	$ 5,018,097	$ 796,443	15.87%	$ 732,746	$ 55,046	$ 787,793	$ 772,335	$ 55,046	$ 827,381	16.49%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	89,246,612	14,814,413	16.60%	13,031,858	978,996	14,010,854	13,735,932	978,996	14,714,928	16.49%
345.05 Accessory Electric Equipment	11,096,944	1,761,241	15.87%	1,620,384	121,729	1,742,113	1,707,929	121,729	1,829,657	16.49%
346.05 Miscellaneous Power Plant Equipment	21,142	3,356	15.87%	3,087	232	3,319	3,254	232	3,486	16.49%
Total Gila Bend	$ 105,382,795	$ 17,375,452	16.49%	$ 15,388,076	$ 1,156,003	$ 16,544,079	$ 16,219,449	$ 1,156,003	$ 17,375,452	16.49%
Hyder										
341.05 Structures and Improvements	$ 6,915,232	$ 1,439,968	20.82%	$ 1,436,869	$ 48,447	$ 1,485,316	$ 1,394,291	$ 48,447	$ 1,442,738	20.86%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	93,250,197	19,712,675	21.14%	19,631,620	661,890	20,293,510	19,049,892	661,890	19,711,782	21.14%
345.05 Accessory Electric Equipment	22,556,482	4,868,348	21.58%	4,846,847	163,262	5,010,110	4,703,229	163,262	4,866,491	21.57%
346.05 Miscellaneous Power Plant Equipment	206,389	47,783	23.15%	47,575	1,597	49,172	46,165	1,597	47,763	23.14%
Total Hyder	$ 122,928,300	$ 26,068,774	21.21%	$ 25,962,911	$ 875,196	$ 26,838,108	$ 25,193,577	$ 875,196	$ 26,068,774	21.21%
Legacy										
341.00 Structures and Improvements	$ 313,214	$ 210,689	67.27%	$ 172,334	$ 441	$ 172,775	$ 336,218	$ 441	$ 336,659	107.49%
342.00 Fuel Holders, Products and Accessories										
343.00 Prime Movers										
344.00 Generators and Devices	10,452,105	6,148,103	58.82%	2,883,339	8,042	2,891,382	5,625,931	8,042	5,633,973	53.90%
345.00 Accessory Electric Equipment	1,972,486	436,675	22.14%	422,124	1,185	423,309	823,649	1,185	824,834	41.82%
346.00 Miscellaneous Power Plant Equipment										
Total Legacy	$ 12,737,805	$ 6,795,467	53.35%	$ 3,477,797	$ 9,668	$ 3,487,466	$ 6,785,798	$ 9,668	$ 6,795,467	53.35%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary - SFAS 143 Method
Vintage Group Procedure
Accretion Rate: 3.78 Percent
December 31, 2018

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
Luke AFB										
341.05 Structures and Improvements	$ 1,488,329	$ 195,442	13.13%	$ 168,976	$ 15,667	$ 184,643	$ 193,853	$ 15,667	$ 209,520	14.08%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	25,469,888	3,634,445	14.27%	2,891,701	268,114	3,159,814	3,317,426	268,114	3,585,540	14.08%
345.05 Accessory Electric Equipment	1,757,020	215,719	12.28%	199,482	18,496	217,977	228,850	18,496	247,346	14.08%
346.05 Miscellaneous Power Plant Equipment	357,678	47,152	13.18%	40,609	3,765	44,374	46,587	3,765	50,352	14.08%
Total Luke AFB	$ 29,072,915	$ 4,092,758	14.08%	$ 3,300,767	$ 306,042	$ 3,606,809	$ 3,786,716	$ 306,042	$ 4,092,758	14.08%
Paloma										
341.05 Structures and Improvements	$ 2,281,950	$ 564,894	24.75%	$ 558,861	$ 36,044	$ 594,905	$ 529,094	$ 36,044	$ 565,139	24.77%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	49,207,939	12,136,521	24.66%	11,999,861	774,223	12,774,083	11,360,700	774,223	12,134,922	24.66%
345.05 Accessory Electric Equipment	12,514,947	3,098,061	24.75%	3,064,973	197,679	3,262,652	2,901,724	197,679	3,099,403	24.77%
346.05 Miscellaneous Power Plant Equipment	121,486	30,074	24.76%	29,753	1,919	31,671	28,168	1,919	30,087	24.77%
Total Paloma	$ 64,126,322	$ 15,829,551	24.68%	$ 15,653,447	$ 1,009,865	$ 16,663,312	$ 14,819,686	$ 1,009,865	$ 15,829,551	24.68%
Red Rock										
341.05 Structures and Improvements	$ 4,463,879	$ 235,358	5.27%	$ 360,140	$ 38,914	$ 399,054	$ 200,370	$ 38,914	$ 239,284	5.36%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	72,010,410	3,796,746	5.27%	5,809,704	627,751	6,437,455	3,232,331	627,751	3,860,082	5.36%
345.05 Accessory Electric Equipment	13,383,040	784,690	5.86%	1,079,726	116,667	1,196,393	600,724	116,667	717,391	5.36%
346.05 Miscellaneous Power Plant Equipment	42,290	2,230	5.27%	3,412	369	3,781	1,898	369	2,267	5.36%
Total Redrock	$ 89,899,619	$ 4,819,024	5.36%	$ 7,252,982	$ 783,700	$ 8,036,682	$ 4,035,324	$ 783,700	$ 4,819,024	5.36%
Roof Tops										
341.05 Structures and Improvements	$ 1,585,418	$ 321,114	20.25%	$ 327,237	$ 41,036	$ 368,273	$ 249,549	$ 41,036	$ 290,585	18.33%
342.05 Fuel Holders, Products and Accessories										
343.05 Prime Movers										
344.05 Generators and Devices	72,791,280	11,318,449	15.55%	12,484,551	1,566,870	14,051,421	9,520,371	1,566,870	11,087,241	15.23%
345.05 Accessory Electric Equipment	16,921,978	2,029,160	11.99%	2,579,186	324,184	2,903,370	1,966,713	324,184	2,290,898	13.54%
346.05 Miscellaneous Power Plant Equipment										
Total Roof Tops	$ 91,298,676	$ 13,668,723	14.97%	$ 15,390,975	$ 1,932,089	$ 17,323,064	$ 11,736,634	$ 1,932,089	$ 13,668,723	14.97%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
STEAM PRODUCTION							
311.00 Structures and Improvements	$ 141,937,433	$ 4,196,141	$ 7,553,262	23.47	0.12%	0.20%	0.32%
312.00 Boiler Plant Equipment	1,491,411,135	57,886,323	87,670,832	24.10	0.16%	0.22%	0.38%
314.00 Turbogenerator Units	211,425,539	7,664,890	12,217,255	24.08	0.15%	0.22%	0.37%
315.00 Accessory Electric Equipment	117,866,116	3,477,632	6,349,965	26.55	0.11%	0.20%	0.32%
316.00 Miscellaneous Power Plant Equipment	84,425,866	2,847,582	4,609,176	24.43	0.14%	0.21%	0.35%
Total Steam Production Plant	$ 2,047,066,089	$ 76,072,568	$ 118,400,490	24.20	0.15%	0.22%	0.37%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$ 850,120,585	$ 888,957	$ 1,925,130	45.35		0.01%	0.01%
322.00 Reactor Plant Equipment	1,187,263,758	3,397,008	7,961,310	46.35	0.01%	0.03%	0.04%
323.00 Turbogenerator Units	405,048,258	427,615	902,047	42.95		0.01%	0.01%
324.00 Accessory Electric Equipment	294,782,526	247,889	664,866	50.24		0.01%	0.01%
325.00 Miscellaneous Power Plant Equipment	233,949,471	302,919	523,373	38.90		0.01%	0.01%
Total Nuclear Production Plant	$ 2,971,164,598	$ 5,264,389	$ 11,976,726	45.24	0.00%	0.02%	0.02%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 131,575,027	$ 2,857,312	$ 3,883,653	26.37	0.08%	0.11%	0.19%
342.00 Fuel Holders, Products and Accessories	56,786,945	977,355	1,689,360	27.20	0.07%	0.11%	0.18%
343.00 Prime Movers	655,542,039	10,316,822	16,973,552	28.66	0.06%	0.10%	0.16%
344.00 Generators and Devices	2,104,937,839	47,839,063	58,566,546	26.98	0.08%	0.10%	0.19%
345.00 Accessory Electric Equipment	247,553,984	6,416,991	8,336,766	26.00	0.10%	0.13%	0.23%
346.00 Miscellaneous Power Plant Equipment	34,845,144	738,273	989,142	22.60	0.09%	0.11%	0.20%
Total Other Production Plant	$ 3,231,240,978	$ 69,145,817	$ 90,439,019	27.15	0.08%	0.11%	0.19%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$ 151,995	$ -	$ -	52.37			
353.00 Station Equipment	132,434,328	1,052,985	1,969,935	53.77	0.01%	0.06%	0.07%
354.00 Towers and Fixtures	1,329,316	-	-	60.66			
355.00 Poles and Fixtures	1,370,085	40,990	75,345	55.56	0.05%	0.21%	0.26%
356.00 Overhead Conductors and Devices	1,947,677	47,471	105,726	59.37	0.04%	0.21%	0.25%
Total Transmission Plant	$ 137,233,401	$ 1,141,445	$ 2,151,006	53.92	0.01%	0.06%	0.07%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$ 93,053,192	$ 1,178,838	$ 2,028,517	59.89	0.02%	0.08%	0.10%
362.00 Station Equipment	631,870,595	7,220,227	11,066,957	45.04	0.03%	0.07%	0.10%
363.00 Storage Battery Equipment	13,585,353	-	-	10.00			
364.01 Poles, Towers and Fixtures - Wood	357,345,350	13,404,937	27,552,144	44.59	0.08%	0.29%	0.37%
364.02 Poles, Towers and Fixtures - Steel	323,911,866	6,471,280	9,017,332	50.07	0.04%	0.11%	0.15%
365.00 Overhead Conductors and Devices	468,658,341	17,842,919	28,422,062	49.93	0.08%	0.23%	0.31%
366.00 Underground Conduit	727,611,816	16,663,040	30,882,504	60.04	0.04%	0.16%	0.20%
367.00 Underground Conductors and Devices	1,863,851,442	68,988,910	114,003,836	39.90	0.09%	0.23%	0.32%
368.00 Line Transformers	921,018,156	7,668,837	14,260,142	55.05	0.02%	0.06%	0.08%
369.00 Services	447,263,911	14,910,594	27,712,829	55.45	0.06%	0.23%	0.29%
370.01 Meters - Electronic	17,843,353	-	-	16.45			
370.03 Meters - AMI	302,666,385	-	-	14.87			
371.00 Installations on Customers' Premises	46,529,246	1,442,607	2,591,254	45.07	0.07%	0.21%	0.28%
373.00 Street Lighting and Signal Systems	80,127,587	1,901,926	3,886,115	54.53	0.04%	0.18%	0.22%
Total Distribution Plant	$ 6,295,336,593	$ 157,694,115	$ 271,423,692	42.43	0.06%	0.16%	0.22%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 265,654,498	$ 7,116,952	$ 9,646,908	39.86	0.07%	0.14%	0.21%
391.CM Office Furn. and Equip. - Computer	243,545,219	-	-	8.16			
397.00 Communication Equipment	295,372,374	-	-	21.06			
Total Depreciable	$ 804,572,091	$ 7,116,952	$ 9,646,908	15.92	0.02%	0.05%	0.07%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$ 63,799,361	$ -	$ -	20.00			
393.00 Stores Equipment	594,181	-	-	20.00			
394.00 Tools, Shop and Garage Equipment	43,094,855	-	-	20.00			
395.00 Laboratory Equipment	767,547	-	-	20.00			
398.00 Miscellaneous Equipment	23,861,303	-	-	24.00			
Total Amortizable	$ 132,117,247	$ -	$ -	20.62			
Total General Plant	$ 936,689,338	$ 7,116,952	$ 9,646,908	16.45	0.02%	0.04%	0.06%
TOTAL UTILITY	$ 15,618,730,997	$ 316,435,286	$ 504,037,842	32.73	0.06%	0.12%	0.18%
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$ 78,078,473	$ 2,304,920	$ 4,436,491	20.20	0.14%	0.21%	0.35%
312.00 Boiler Plant Equipment	385,237,434	13,128,990	22,665,878	18.69	0.18%	0.22%	0.40%
314.00 Turbogenerator Units	85,554,772	2,720,232	5,034,520	20.81	0.16%	0.22%	0.38%
315.00 Accessory Electric Equipment	53,298,558	1,247,782	3,044,205	25.48	0.10%	0.22%	0.31%
316.00 Miscellaneous Power Plant Equipment	24,674,267	852,434	1,445,964	17.23	0.20%	0.22%	0.42%
Total Cholla	$ 626,843,504	$ 20,254,357	$ 36,627,058	19.52	0.17%	0.22%	0.39%
Cholla Unit 1							
311.00 Structures and Improvements	$ 4,743,207	$ 140,734	$ 305,078	23.89	0.12%	0.24%	0.36%
312.00 Boiler Plant Equipment	82,295,074	3,135,055	5,467,554	19.18	0.20%	0.25%	0.45%
314.00 Turbogenerator Units	27,444,492	1,076,513	1,803,956	18.42	0.21%	0.25%	0.46%
315.00 Accessory Electric Equipment	9,492,908	291,946	617,403	23.08	0.13%	0.25%	0.38%
316.00 Miscellaneous Power Plant Equipment	3,742,187	133,896	246,005	18.93	0.19%	0.25%	0.44%
Total Cholla Unit 1	$ 127,717,868	$ 4,778,143	$ 8,439,996	19.39	0.19%	0.25%	0.44%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Cholla Unit 3							
311.00 Structures and Improvements	$ 13,288,725	$ 353,293	$ 719,288	20.30	0.13%	0.20%	0.33%
312.00 Boiler Plant Equipment	243,068,426	8,029,319	13,669,446	18.24	0.18%	0.21%	0.39%
314.00 Turbogenerator Units	57,062,305	1,613,053	3,169,520	22.21	0.13%	0.21%	0.34%
315.00 Accessory Electric Equipment	34,899,789	658,874	1,914,442	30.16	0.06%	0.21%	0.27%
316.00 Miscellaneous Power Plant Equipment	7,009,816	212,527	389,362	18.06	0.17%	0.21%	0.38%
Total Cholla Unit 3	$ 355,329,061	$ 10,867,066	$ 19,862,058	19.64	0.16%	0.21%	0.37%
Cholla Common							
311.00 Structures and Improvements	$ 60,046,541	$ 1,810,893	$ 3,412,126	19.93	0.15%	0.21%	0.36%
312.00 Boiler Plant Equipment	59,873,934	1,964,616	3,528,878	20.01	0.16%	0.22%	0.38%
314.00 Turbogenerator Units	1,047,975	30,666	61,044	20.15	0.15%	0.22%	0.37%
315.00 Accessory Electric Equipment	8,905,861	296,961	512,360	17.03	0.20%	0.22%	0.42%
316.00 Miscellaneous Power Plant Equipment	13,922,264	506,011	810,597	16.45	0.22%	0.22%	0.44%
Total Cholla Common	$ 143,796,575	$ 4,609,148	$ 8,325,004	19.36	0.16%	0.22%	0.38%
Four Corners							
311.00 Structures and Improvements	$ 63,858,960	$ 1,891,221	$ 3,116,770	29.26	0.10%	0.18%	0.28%
312.00 Boiler Plant Equipment	1,106,173,701	44,757,333	65,004,955	26.80	0.15%	0.22%	0.37%
314.00 Turbogenerator Units	125,870,767	4,944,659	7,182,735	26.95	0.15%	0.22%	0.37%
315.00 Accessory Electric Equipment	64,567,558	2,229,850	3,305,760	27.51	0.13%	0.19%	0.32%
316.00 Miscellaneous Power Plant Equipment	59,751,599	1,995,148	3,163,212	29.53	0.12%	0.20%	0.32%
Total Four Corners	$ 1,420,222,585	$ 55,818,211	$ 81,773,432	27.05	0.14%	0.21%	0.36%
Four Corners Units 4-5							
311.00 Structures and Improvements	$ 39,839,762	$ 1,120,521	$ 2,148,968	33.84	0.08%	0.20%	0.28%
312.00 Boiler Plant Equipment	1,066,430,407	43,579,974	63,192,532	26.74	0.15%	0.22%	0.37%
314.00 Turbogenerator Units	121,897,287	4,853,608	7,008,068	26.81	0.15%	0.22%	0.37%
315.00 Accessory Electric Equipment	43,201,151	1,499,635	2,407,686	29.84	0.12%	0.21%	0.33%
316.00 Miscellaneous Power Plant Equipment	39,853,780	1,405,666	2,291,519	30.51	0.12%	0.22%	0.34%
Total Four Corners Units 4-5	$ 1,311,222,387	$ 52,459,405	$ 77,048,773	27.11	0.15%	0.22%	0.37%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Four Corners Common							
311.00 Structures and Improvements	$ 24,019,198	$ 770,700	$ 967,803	23.89	0.13%	0.15%	0.28%
312.00 Boiler Plant Equipment	39,743,294	1,177,359	1,812,422	28.59	0.10%	0.17%	0.27%
314.00 Turbogenerator Units	3,973,480	91,050	174,667	32.27	0.07%	0.17%	0.24%
315.00 Accessory Electric Equipment	21,366,407	730,216	898,074	23.75	0.14%	0.16%	0.30%
316.00 Miscellaneous Power Plant Equipment	19,897,819	589,481	871,693	27.75	0.11%	0.17%	0.28%
Total Four Corners Common	$ 109,000,198	$ 3,358,806	$ 4,724,659	26.36	0.12%	0.16%	0.28%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$ 850,120,585	$ 888,957	$ 1,925,130	45.35		0.01%	0.01%
322.00 Reactor Plant Equipment	1,187,263,758	3,397,008	7,961,310	46.35	0.01%	0.03%	0.04%
323.00 Turbogenerator Units	405,048,258	427,615	902,047	42.95		0.01%	0.01%
324.00 Accessory Electric Equipment	294,782,526	247,889	664,866	50.24		0.01%	0.01%
325.00 Miscellaneous Power Plant Equipment	233,949,471	302,919	523,373	38.90		0.01%	0.01%
Total Palo Verde	$ 2,971,164,598	$ 5,264,389	$ 11,976,726	45.24	0.00%	0.02%	0.02%
Palo Verde Unit 1							
321.00 Structures and Improvements	$ 169,287,979	$ 131,843	$ 371,003	50.06		0.01%	0.01%
322.00 Reactor Plant Equipment	465,986,593	1,219,609	3,039,081	46.74	0.01%	0.02%	0.03%
323.00 Turbogenerator Units	144,321,116	143,865	311,362	42.19		0.01%	0.01%
324.00 Accessory Electric Equipment	121,319,415	91,271	266,311	51.10		0.01%	0.01%
325.00 Miscellaneous Power Plant Equipment	33,599,919	27,627	73,371	46.77		0.01%	0.01%
Total Palo Verde Unit 1	$ 934,515,022	$ 1,614,216	$ 4,061,128	47.04	0.00%	0.01%	0.02%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Palo Verde Unit 2							
321.00 Structures and Improvements	$ 94,477,904	$ 71,418	$ 212,470	52.67		0.01%	0.01%
322.00 Reactor Plant Equipment	248,880,636	711,614	1,654,745	45.28	0.01%	0.03%	0.04%
323.00 Turbogenerator Units	87,819,612	89,829	193,897	42.92		0.01%	0.01%
324.00 Accessory Electric Equipment	49,752,711	39,761	111,470	50.84		0.01%	0.01%
325.00 Miscellaneous Power Plant Equipment	27,865,592	23,438	62,103	48.77		0.01%	0.01%
Total Palo Verde Unit 2	$ 508,796,455	$ 936,059	$ 2,234,685	46.74	0.00%	0.02%	0.02%
Palo Verde Unit 3							
321.00 Structures and Improvements	$ 167,896,725	$ 138,955	$ 392,415	53.18		0.01%	0.01%
322.00 Reactor Plant Equipment	436,634,437	1,346,614	3,020,830	46.77	0.01%	0.03%	0.04%
323.00 Turbogenerator Units	167,364,071	184,913	384,474	44.00		0.01%	0.01%
324.00 Accessory Electric Equipment	95,765,260	84,279	223,115	51.24		0.01%	0.01%
325.00 Miscellaneous Power Plant Equipment	29,878,581	26,912	69,461	49.39		0.01%	0.01%
Total Palo Verde Unit 3	$ 897,539,074	$ 1,781,673	$ 4,090,294	47.82	0.00%	0.02%	0.02%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$ 233,902,104	$ 312,378	$ 529,445	39.56		0.01%	0.01%
322.00 Reactor Plant Equipment	454,911	2,473	3,006	32.04	0.02%	0.02%	0.04%
323.00 Turbogenerator Units	217,756	179	508	51.39		0.01%	0.01%
324.00 Accessory Electric Equipment	-	-	-				
325.00 Miscellaneous Power Plant Equipment	241,107	376	539	35.63		0.01%	0.01%
Total Palo Verde Water Reclamation	$ 234,815,878	$ 315,406	$ 533,498	39.55	0.00%	0.01%	0.01%
Palo Verde Common							
321.00 Structures and Improvements	$ 184,555,873	$ 234,363	$ 419,797	40.99		0.01%	0.01%
322.00 Reactor Plant Equipment	35,307,181	116,699	243,647	44.29	0.01%	0.03%	0.04%
323.00 Turbogenerator Units	5,325,703	8,829	11,805	34.21		0.01%	0.01%
324.00 Accessory Electric Equipment	27,945,140	32,579	63,971	43.28		0.01%	0.01%
325.00 Miscellaneous Power Plant Equipment	142,364,272	224,567	317,899	34.62		0.01%	0.01%
Total Palo Verde Common	$ 395,498,169	$ 617,036	$ 1,057,120	38.72	0.00%	0.01%	0.01%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
OTHER PRODUCTION							
Combined Cycle							
341.00 Structures and Improvements	$ 63,600,586	$ 1,052,766	$ 1,605,086	28.02	0.06%	0.10%	0.15%
342.00 Fuel Holders, Products and Accessories	41,829,313	779,583	1,249,198	25.59	0.07%	0.11%	0.19%
343.00 Prime Movers	274,702,584	3,829,150	6,980,448	30.91	0.05%	0.10%	0.14%
344.00 Generators and Devices	727,795,468	13,992,081	19,385,049	23.57	0.08%	0.10%	0.18%
345.00 Accessory Electric Equipment	78,442,697	1,578,344	2,225,300	22.11	0.10%	0.11%	0.20%
346.00 Miscellaneous Power Plant Equipment	20,741,997	447,056	584,386	21.46	0.10%	0.11%	0.21%
Total Combined Cycle	$ 1,207,112,645	$ 21,678,981	$ 32,029,467	25.05	0.07%	0.10%	0.17%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$ 23,988,173	$ 360,778	$ 612,663	29.85	0.05%	0.10%	0.15%
342.00 Fuel Holders, Products and Accessories	12,809,613	258,726	327,020	23.95	0.08%	0.10%	0.18%
343.00 Prime Movers	132,414,998	1,844,965	3,382,231	29.97	0.05%	0.10%	0.15%
344.00 Generators and Devices	391,212,295	7,467,008	9,988,492	23.58	0.08%	0.10%	0.18%
345.00 Accessory Electric Equipment	29,897,838	497,247	763,512	27.20	0.06%	0.10%	0.16%
346.00 Miscellaneous Power Plant Equipment	6,872,469	136,627	175,453	24.23	0.08%	0.10%	0.18%
Total Redhawk CC Units 1-2	$ 597,195,386	$ 10,565,350	$ 15,249,373	25.17	0.07%	0.10%	0.17%
West Phoenix							
341.00 Structures and Improvements	$ 39,612,413	$ 691,988	$ 992,422	27.02	0.06%	0.09%	0.16%
342.00 Fuel Holders, Products and Accessories	29,019,700	520,857	922,178	26.39	0.07%	0.12%	0.19%
343.00 Prime Movers	142,287,586	1,984,185	3,598,217	31.84	0.05%	0.09%	0.14%
344.00 Generators and Devices	336,583,173	6,525,073	9,396,557	23.56	0.08%	0.10%	0.19%
345.00 Accessory Electric Equipment	48,544,859	1,081,097	1,461,787	19.82	0.12%	0.11%	0.23%
346.00 Miscellaneous Power Plant Equipment	13,869,528	310,429	408,933	20.31	0.11%	0.11%	0.22%
Total West Phoenix	$ 609,917,259	$ 11,113,630	$ 16,780,094	24.94	0.08%	0.10%	0.18%

ARIZONA PUBLIC SERVICE COMPANY

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Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$ 366,217	$ 7,403	$ 11,992	23.84	0.08%	0.12%	0.20%
342.00 Fuel Holders, Products and Accessories	22,031,967	392,512	721,500	26.79	0.07%	0.12%	0.19%
343.00 Prime Movers	-	-	-				
344.00 Generators and Devices	130,345,213	2,842,313	4,268,149	20.16	0.11%	0.12%	0.23%
345.00 Accessory Electric Equipment	32,620,455	817,335	1,068,075	17.23	0.15%	0.12%	0.27%
346.00 Miscellaneous Power Plant Equipment	8,073,969	192,437	264,371	18.33	0.13%	0.12%	0.25%
Total West Phoenix CC Units 1-3	$ 193,437,821	$ 4,252,001	$ 6,334,088	20.07	0.11%	0.12%	0.23%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$ 7,035,987	$ 129,422	$ 186,071	25.36	0.07%	0.10%	0.17%
342.00 Fuel Holders, Products and Accessories	4,470,010	64,740	118,242	32.60	0.04%	0.10%	0.14%
343.00 Prime Movers	49,464,010	687,553	1,308,493	33.48	0.04%	0.10%	0.14%
344.00 Generators and Devices	23,956,815	413,431	633,588	27.29	0.06%	0.10%	0.16%
345.00 Accessory Electric Equipment	552,377	11,134	14,606	23.88	0.08%	0.10%	0.18%
346.00 Miscellaneous Power Plant Equipment	942,600	21,061	24,920	21.46	0.10%	0.10%	0.20%
Total West Phoenix CC Unit 4	$ 86,421,799	$ 1,327,342	$ 2,285,919	30.46	0.05%	0.10%	0.15%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$ 11,054,705	$ 168,986	$ 272,660	30.89	0.05%	0.09%	0.14%
342.00 Fuel Holders, Products and Accessories	2,517,723	63,605	82,435	17.95	0.14%	0.12%	0.26%
343.00 Prime Movers	92,823,576	1,296,633	2,289,724	31.03	0.05%	0.09%	0.14%
344.00 Generators and Devices	182,281,145	3,269,329	4,494,819	26.25	0.07%	0.09%	0.16%
345.00 Accessory Electric Equipment	15,372,027	252,628	379,106	28.84	0.06%	0.09%	0.15%
346.00 Miscellaneous Power Plant Equipment	4,852,959	96,931	119,642	24.43	0.08%	0.09%	0.17%
Total West Phoenix CC Unit 5	$ 308,902,135	$ 5,148,112	$ 7,638,387	27.67	0.06%	0.09%	0.15%

ARIZONA PUBLIC SERVICE COMPANY

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Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
West Phoenix Common							
341.00 Structures and Improvements	$ 21,155,504	$ 386,176	$ 521,700	25.95	0.07%	0.09%	0.16%
342.00 Fuel Holders, Products and Accessories	-	-	-				
343.00 Prime Movers	-	-	-				
344.00 Generators and Devices	-	-	-				
345.00 Accessory Electric Equipment	-	-	-				
346.00 Miscellaneous Power Plant Equipment	-	-	-				
Total West Phoenix Common	$ 21,155,504	$ 386,176	$ 521,700	25.95	0.07%	0.09%	0.16%
Combustion Turbine							
341.00 Structures and Improvements	$ 31,102,449	$ 651,846	$ 906,401	21.51	0.10%	0.11%	0.21%
342.00 Fuel Holders, Products and Accessories	14,957,632	197,772	440,162	33.00	0.04%	0.11%	0.15%
343.00 Prime Movers	380,839,455	6,487,672	9,993,104	27.23	0.06%	0.10%	0.16%
344.00 Generators and Devices	689,863,781	11,329,513	12,304,957	29.81	0.06%	0.07%	0.12%
345.00 Accessory Electric Equipment	42,078,140	703,317	1,165,408	27.64	0.06%	0.11%	0.16%
346.00 Miscellaneous Power Plant Equipment	12,525,501	242,561	346,791	24.06	0.08%	0.11%	0.18%
Total Combustion Turbine	$ 1,171,366,958	$ 19,612,681	$ 25,156,822	28.52	0.06%	0.08%	0.14%
Douglas CT							
341.00 Structures and Improvements	$ 103,952	$ 2,231	$ 3,404	22.09	0.10%	0.12%	0.22%
342.00 Fuel Holders, Products and Accessories	137,759	1,294	4,513	42.07	0.02%	0.12%	0.14%
343.00 Prime Movers	3,721,569	93,907	121,857	17.15	0.15%	0.12%	0.27%
344.00 Generators and Devices	971,924	14,919	31,836	26.61	0.06%	0.12%	0.18%
345.00 Accessory Electric Equipment	582,402	9,829	19,076	23.76	0.07%	0.12%	0.19%
346.00 Miscellaneous Power Plant Equipment	33,564	334	1,099	42.09	0.02%	0.12%	0.14%
Total Douglas CT	$ 5,551,170	$ 122,515	$ 181,786	19.35	0.12%	0.12%	0.24%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Ocotillo							
341.00 Structures and Improvements	$ 3,189,602	$ 86,082	$ 104,432	15.79	0.17%	0.12%	0.29%
342.00 Fuel Holders, Products and Accessories	1,484,432	29,004	48,613	22.36	0.09%	0.12%	0.21%
343.00 Prime Movers	24,161,626	577,250	791,159	18.45	0.13%	0.12%	0.25%
344.00 Generators and Devices	612,033,648	9,778,016	10,023,925	31.19	0.05%	0.06%	0.11%
345.00 Accessory Electric Equipment	4,017,658	81,176	131,573	21.74	0.09%	0.12%	0.21%
346.00 Miscellaneous Power Plant Equipment	950,460	15,348	31,130	26.73	0.06%	0.12%	0.18%
Total Ocotillo	$ 645,837,426	$ 10,566,877	$ 11,130,832	30.15	0.06%	0.06%	0.12%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$ 3,189,602	$ 86,082	$ 104,432	15.79	0.17%	0.12%	0.29%
342.00 Fuel Holders, Products and Accessories	1,484,432	29,004	48,613	22.36	0.09%	0.12%	0.21%
343.00 Prime Movers	24,161,626	577,250	791,159	18.45	0.13%	0.12%	0.25%
344.00 Generators and Devices	15,486,821	340,359	507,122	20.16	0.11%	0.12%	0.23%
345.00 Accessory Electric Equipment	4,017,658	81,176	131,573	21.74	0.09%	0.12%	0.21%
346.00 Miscellaneous Power Plant Equipment	950,460	15,348	31,130	26.73	0.06%	0.12%	0.18%
Total Octillo CT Units 1-2	$ 49,290,599	$ 1,129,220	$ 1,614,030	19.21	0.12%	0.12%	0.24%
Ocotillo CT Units 3-7							
341.00 Structures and Improvements	$ -	$ -	$ -				
342.00 Fuel Holders, Products and Accessories	-	-	-				
343.00 Prime Movers	-	-	-				
344.00 Generators and Devices	596,546,827	9,437,657	9,516,802	31.64	0.05%	0.06%	0.11%
345.00 Accessory Electric Equipment	-	-	-				
346.00 Miscellaneous Power Plant Equipment	-	-	-				
Total Octillo CT Units 3-7	$ 596,546,827	$ 9,437,657	$ 9,516,802	31.64	0.05%	0.06%	0.11%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Saguaro							
341.00 Structures and Improvements	$ 3,051,365	$ 66,535	$ 99,918	20.90	0.10%	0.12%	0.22%
342.00 Fuel Holders, Products and Accessories	1,642,488	19,288	53,805	34.90	0.03%	0.12%	0.15%
343.00 Prime Movers	23,292,483	551,111	748,730	17.65	0.14%	0.12%	0.25%
344.00 Generators and Devices	38,498,152	707,728	1,089,368	23.87	0.09%	0.11%	0.19%
345.00 Accessory Electric Equipment	3,593,189	71,044	115,338	21.69	0.09%	0.12%	0.21%
346.00 Miscellaneous Power Plant Equipment	916,172	12,545	30,009	32.45	0.04%	0.12%	0.16%
Total Saguaro	$ 70,993,849	$ 1,428,251	$ 2,137,169	21.39	0.10%	0.11%	0.21%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$ 3,051,365	$ 66,535	$ 99,918	20.90	0.10%	0.12%	0.22%
342.00 Fuel Holders, Products and Accessories	1,642,488	19,288	53,805	34.90	0.03%	0.12%	0.15%
343.00 Prime Movers	21,353,178	513,961	699,216	17.18	0.14%	0.12%	0.26%
344.00 Generators and Devices	14,724,431	376,141	482,125	16.22	0.16%	0.12%	0.28%
345.00 Accessory Electric Equipment	3,269,324	64,637	107,070	21.48	0.09%	0.12%	0.21%
346.00 Miscellaneous Power Plant Equipment	916,172	12,545	30,009	32.45	0.04%	0.12%	0.16%
Total Saguaro CT Units 1-2	$ 44,956,958	$ 1,053,108	$ 1,472,143	17.81	0.13%	0.12%	0.25%
Saguaro CT Unit 3							
341.00 Structures and Improvements	$ -	$ -	$ -				
342.00 Fuel Holders, Products and Accessories	-	-	-				
343.00 Prime Movers	1,939,305	37,149	49,514	25.18	0.08%	0.10%	0.18%
344.00 Generators and Devices	23,773,721	331,587	607,243	33.73	0.04%	0.10%	0.14%
345.00 Accessory Electric Equipment	323,865	6,407	8,269	24.03	0.08%	0.10%	0.18%
346.00 Miscellaneous Power Plant Equipment	-	-	-				
Total Saguaro CT Unit 3	$ 26,036,891	$ 375,143	$ 665,026	32.74	0.04%	0.10%	0.14%

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Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Sundance Units 1-10							
341.00 Structures and Improvements	$ 13,762,067	$ 228,879	$ 351,434	28.79	0.06%	0.10%	0.16%
342.00 Fuel Holders, Products and Accessories	4,418,231	71,438	112,830	29.69	0.05%	0.10%	0.15%
343.00 Prime Movers	227,932,672	3,636,454	5,820,901	30.06	0.05%	0.10%	0.15%
344.00 Generators and Devices	13,058,506	290,562	333,328	21.70	0.10%	0.10%	0.20%
345.00 Accessory Electric Equipment	27,804,255	451,976	710,043	29.56	0.05%	0.10%	0.15%
346.00 Miscellaneous Power Plant Equipment	6,970,933	155,056	177,943	21.27	0.10%	0.10%	0.20%
Total Sun Dance Units 1-10	$ 293,946,664	$ 4,834,365	$ 7,506,479	29.16	0.05%	0.10%	0.15%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$ 4,239,486	$ 111,306	$ 138,810	16.36	0.16%	0.12%	0.28%
342.00 Fuel Holders, Products and Accessories	1,843,219	24,511	60,378	30.97	0.04%	0.12%	0.16%
343.00 Prime Movers	20,466,623	440,687	670,218	20.55	0.10%	0.12%	0.22%
344.00 Generators and Devices	15,280,205	369,675	500,343	17.28	0.14%	0.12%	0.26%
345.00 Accessory Electric Equipment	1,525,954	22,220	49,983	28.63	0.05%	0.12%	0.17%
346.00 Miscellaneous Power Plant Equipment	1,026,473	15,918	33,619	29.90	0.05%	0.12%	0.17%
Total West Phoenix CT Units 1-2	$ 44,381,960	$ 984,318	$ 1,453,349	19.41	0.11%	0.12%	0.23%
Yucca							
341.00 Structures and Improvements	$ 6,755,977	$ 156,813	$ 208,402	18.98	0.13%	0.11%	0.24%
342.00 Fuel Holders, Products and Accessories	5,431,503	52,236	160,023	42.38	0.03%	0.11%	0.13%
343.00 Prime Movers	81,264,482	1,188,262	1,840,239	31.75	0.04%	0.09%	0.13%
344.00 Generators and Devices	10,021,346	168,612	326,158	25.89	0.07%	0.12%	0.19%
345.00 Accessory Electric Equipment	4,554,682	67,072	139,394	29.64	0.05%	0.11%	0.16%
346.00 Miscellaneous Power Plant Equipment	2,627,899	43,360	72,991	27.99	0.06%	0.10%	0.16%
Total Yucca	$ 110,655,889	$ 1,676,355	$ 2,747,207	30.08	0.05%	0.09%	0.14%

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Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Yucca CT Units 1-4							
341.00 Structures and Improvements	$ 5,685,548	$ 139,735	$ 186,167	17.72	0.14%	0.12%	0.26%
342.00 Fuel Holders, Products and Accessories	3,934,860	30,921	128,926	47.16	0.02%	0.12%	0.14%
343.00 Prime Movers	12,670,962	198,541	415,044	25.97	0.06%	0.12%	0.18%
344.00 Generators and Devices	9,848,867	165,776	322,575	25.83	0.07%	0.12%	0.19%
345.00 Accessory Electric Equipment	3,737,069	53,511	122,412	29.75	0.05%	0.12%	0.17%
346.00 Miscellaneous Power Plant Equipment	1,536,718	22,778	50,335	29.27	0.05%	0.12%	0.17%
Total Yucca CT Units 1-4	$ 37,414,024	$ 611,262	$ 1,225,460	25.77	0.07%	0.12%	0.19%
Yucca CT Units 5-6							
341.00 Structures and Improvements	$ 1,070,429	$ 17,078	$ 22,235	30.53	0.05%	0.08%	0.13%
342.00 Fuel Holders, Products and Accessories	1,496,643	21,316	31,097	33.47	0.04%	0.08%	0.12%
343.00 Prime Movers	68,593,520	989,721	1,425,195	33.11	0.04%	0.08%	0.12%
344.00 Generators and Devices	172,479	2,836	3,582	29.72	0.06%	0.08%	0.14%
345.00 Accessory Electric Equipment	817,613	13,561	16,982	29.14	0.06%	0.08%	0.14%
346.00 Miscellaneous Power Plant Equipment	1,091,181	20,582	22,656	26.36	0.07%	0.08%	0.15%
Total Yucca CT Units 5-6	$ 73,241,865	$ 1,065,094	$ 1,521,747	32.89	0.04%	0.08%	0.12%
Solar Units							
341.00 Structures and Improvements	$ 36,871,992	$ 1,152,700	$ 1,372,167	28.94	0.11%	0.14%	0.25%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	687,278,590	22,517,469	26,876,540	28.64	0.11%	0.15%	0.26%
345.00 Accessory Electric Equipment	127,033,147	4,135,330	4,946,058	28.54	0.11%	0.15%	0.26%
346.00 Miscellaneous Power Plant Equipment	1,577,646	48,656	57,965	29.01	0.11%	0.14%	0.25%
Total Solar Units	$ 852,761,375	$ 27,854,155	$ 33,252,730	28.64	0.11%	0.15%	0.26%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Chino Valley							
341.05 Structures and Improvements	$ 527,890	$ 13,061	$ 16,494	28.93	0.09%	0.12%	0.21%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	77,719,184	1,922,867	2,428,305	28.93	0.09%	0.12%	0.21%
345.05 Accessory Electric Equipment	6,511,784	161,109	203,458	28.93	0.09%	0.12%	0.21%
346.05 Miscellaneous Power Plant Equipment	216,504	5,357	6,765	28.93	0.09%	0.12%	0.21%
Total Chino Valley	$ 84,975,362	$ 2,102,394	$ 2,655,022	28.93	0.09%	0.12%	0.21%
Cotton Center							
341.05 Structures and Improvements	$ 1,813,499	$ 41,757	$ 54,745	28.95	0.08%	0.11%	0.19%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	62,644,922	1,452,335	1,891,083	28.75	0.08%	0.11%	0.19%
345.05 Accessory Electric Equipment	15,418,007	355,011	465,430	28.95	0.08%	0.11%	0.19%
346.05 Miscellaneous Power Plant Equipment	262,640	6,047	7,928	28.95	0.08%	0.11%	0.19%
Total Cotton Center	$ 80,139,068	$ 1,855,151	$ 2,419,186	28.79	0.08%	0.11%	0.19%
Desert Star							
341.05 Structures and Improvements	$ 1,557,800	$ 56,810	$ 64,118	28.89	0.13%	0.16%	0.29%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	29,042,805	1,081,918	1,195,408	28.31	0.13%	0.16%	0.29%
345.05 Accessory Electric Equipment	4,084,919	148,969	168,132	28.89	0.13%	0.16%	0.29%
346.05 Miscellaneous Power Plant Equipment	291,809	10,642	12,011	28.89	0.13%	0.16%	0.29%
Total Desert Star	$ 34,977,333	$ 1,298,339	$ 1,439,669	28.41	0.13%	0.16%	0.29%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Foothills Units							
341.05 Structures and Improvements	$ 10,906,684	$ 312,283	$ 379,870	28.91	0.10%	0.13%	0.23%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	105,443,248	3,019,090	3,672,490	28.91	0.10%	0.13%	0.23%
345.05 Accessory Electric Equipment	20,815,540	595,996	724,986	28.91	0.10%	0.13%	0.23%
346.05 Miscellaneous Power Plant Equipment	57,708	1,652	2,010	28.91	0.10%	0.13%	0.23%
Total Foothills Units	$ 137,223,180	$ 3,929,021	$ 4,779,355	28.91	0.10%	0.13%	0.23%
Gila Bend							
341.05 Structures and Improvements	$ 5,018,097	$ 173,216	$ 202,955	28.90	0.12%	0.15%	0.27%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	89,246,612	3,080,632	3,609,549	28.90	0.12%	0.15%	0.27%
345.05 Accessory Electric Equipment	11,096,944	383,047	448,812	28.90	0.12%	0.15%	0.27%
346.05 Miscellaneous Power Plant Equipment	21,142	730	855	28.90	0.12%	0.15%	0.27%
Total Gila Bend	$ 105,382,795	$ 3,637,624	$ 4,262,172	28.90	0.12%	0.15%	0.27%
Hyder							
341.05 Structures and Improvements	$ 6,915,232	$ 104,623	$ 131,433	28.78	0.05%	0.07%	0.12%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	93,250,197	1,405,267	1,772,362	28.88	0.05%	0.07%	0.12%
345.05 Accessory Electric Equipment	22,556,482	337,811	428,729	29.04	0.05%	0.07%	0.12%
346.05 Miscellaneous Power Plant Equipment	206,389	3,021	3,923	29.63	0.05%	0.07%	0.12%
Total Hyder	$ 122,928,300	$ 1,850,723	$ 2,336,446	28.90	0.05%	0.07%	0.12%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Legacy							
341.00 Structures and Improvements	$ 313,214	$ 224	$ 546	40.13		0.01%	0.01%
342.00 Fuel Holders, Products and Accessories	-	-	-				
343.00 Prime Movers	-	-	-				
344.00 Generators and Devices	10,452,105	12,663	17,526	24.94		0.01%	0.01%
345.00 Accessory Electric Equipment	1,972,486	2,642	3,278	22.99	0.01%	0.01%	0.02%
346.00 Miscellaneous Power Plant Equipment	-	-	-				
Total Legacy	$ 12,737,805	$ 15,529	$ 21,350	24.84	0.00%	0.01%	0.01%
Luke AFB							
341.05 Structures and Improvements	$ 1,488,329	$ 64,746	$ 73,072	28.89	0.15%	0.19%	0.34%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	25,469,888	1,108,005	1,250,484	28.89	0.15%	0.19%	0.34%
345.05 Accessory Electric Equipment	1,757,020	76,435	86,264	28.89	0.15%	0.19%	0.34%
346.05 Miscellaneous Power Plant Equipment	357,678	15,560	17,561	28.89	0.15%	0.19%	0.34%
Total Luke AFB	$ 29,072,915	$ 1,264,746	$ 1,427,380	28.89	0.15%	0.19%	0.34%
Paloma							
341.05 Structures and Improvements	$ 2,281,950	$ 64,839	$ 85,001	28.95	0.10%	0.14%	0.24%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	49,207,939	1,399,934	1,832,958	28.91	0.10%	0.14%	0.24%
345.05 Accessory Electric Equipment	12,514,947	355,596	466,172	28.95	0.10%	0.14%	0.24%
346.05 Miscellaneous Power Plant Equipment	121,486	3,452	4,525	28.95	0.10%	0.14%	0.24%
Total Paloma	$ 64,126,322	$ 1,823,821	$ 2,388,656	28.92	0.10%	0.14%	0.24%

ARIZONA PUBLIC SERVICE COMPANY
Net Salvage Accrual Rates - SFAS 143 Method
Accretion Rate (r): 3.78 Percent

Statement D

Account Description	12/31/18 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Red Rock							
341.05 Structures and Improvements	$ 4,463,879	$ 231,767	$ 251,951	28.88	0.18%	0.21%	0.39%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	72,010,410	3,738,814	4,064,428	28.88	0.18%	0.21%	0.39%
345.05 Accessory Electric Equipment	13,383,040	694,854	755,369	28.88	0.18%	0.21%	0.39%
346.05 Miscellaneous Power Plant Equipment	42,290	2,196	2,387	28.88	0.18%	0.21%	0.39%
Total Redrock	$ 89,899,619	$ 4,667,630	$ 5,074,135	28.88	0.18%	0.21%	0.39%
Roof Tops							
341.05 Structures and Improvements	$ 1,585,418	$ 89,374	$ 111,982	28.73	0.20%	0.27%	0.47%
342.05 Fuel Holders, Products and Accessories	-	-	-				
343.05 Prime Movers	-	-	-				
344.05 Generators and Devices	72,791,280	4,295,944	5,141,948	27.52	0.21%	0.27%	0.48%
345.05 Accessory Electric Equipment	16,921,978	1,023,859	1,195,428	26.90	0.22%	0.27%	0.49%
346.05 Miscellaneous Power Plant Equipment	-	-	-				
Total Roof Tops	$ 91,298,676	$ 5,409,178	$ 6,449,359	27.42	0.21%	0.27%	0.48%

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

		Current Parameters						SFAS 143 Method					
		P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
	nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
	A	B	C	D	E	F	G	H	I	J	K	L	M
	STEAM PRODUCTION												
311.00	Structures and Improvements									23.47	10.98	-8.5	
312.00	Boiler Plant Equipment									24.10	14.83	-10.6	
314.00	Turbogenerator Units									24.08	13.13	-9.9	
315.00	Accessory Electric Equipment									26.55	13.09	-9.0	
316.00	Miscellaneous Power Plant Equipment									24.43	13.80	-9.7	
	Total Steam Production Plant									24.20	14.24	-10.2	
	NUCLEAR PRODUCTION												
321.00	Structures and Improvements									45.35	26.75	-0.4	
322.00	Reactor Plant Equipment									46.35	25.94	-1.0	
323.00	Turbogenerator Units									42.95	26.01	-0.3	
324.00	Accessory Electric Equipment									50.24	25.98	-0.4	
325.00	Miscellaneous Power Plant Equipment									38.90	26.94	-0.4	
	Total Nuclear Production Plant									45.24	26.28	-0.6	
	OTHER PRODUCTION												
341.00	Structures and Improvements									26.37	18.48	-6.2	
342.00	Fuel Holders, Products and Accessories									27.20	14.18	-5.0	
343.00	Prime Movers									28.66	17.38	-5.0	
344.00	Generators and Devices									26.98	22.18	-6.5	
345.00	Accessory Electric Equipment									26.00	18.87	-7.3	
346.00	Miscellaneous Power Plant Equipment									22.60	15.93	-5.2	
	Total Other Production Plant									27.15	20.62	-6.2	
	TRANSMISSION PLANT												
352.02	Structures and Improvements	50.00	R4	51.64	12.17			50.00	R4	52.37	10.25		0.0
353.00	Station Equipment	53.00	R1.5	53.86	41.27	-4.5	-5.0	53.00	R1.5	53.77	40.72	-5.0	-3.5
354.00	Towers and Fixtures	60.00	R3	60.47	32.86			60.00	R3	60.66	30.40		-0.1
355.00	Poles and Fixtures	55.00	R1.5	55.37	44.16	-20.0	-20.0	55.00	R1.5	55.56	41.88	-20.0	-14.2
356.00	Overhead Conductors and Devices	60.00	R3	59.50	42.77	-18.7	-20.0	60.00	R3	59.37	40.12	-20.0	-13.8
	Total Transmission Plant									53.92	40.60	-5.3	

ARIZONA PUBLIC SERVICE COMPANY

Statement E

Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

		Current Parameters						SFAS 143 Method					
		P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
	nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
	A	B	C	D	E	F	G	H	I	J	K	L	M
	DISTRIBUTION PLANT												
361.00	Structures and Improvements	60.00	R3	59.90	48.10	-5.1	-5.0	60.00	R3	59.89	47.27	-10.0	-5.7
362.00	Station Equipment	43.00	L0.5	43.08	35.03	-3.8	-5.0	45.00	L0.5	45.04	37.26	-5.0	-4.4
363.00	Storage Battery Equipment	10.00	S3	10.00	6.51			10.00	S3	10.00	8.68		0.0
364.01	Poles, Towers and Fixtures - Wood	45.00	L0	44.55	34.73	-9.3	-10.0	45.00	L0	44.59	34.63	-20.0	-17.5
364.02	Poles, Towers and Fixtures - Steel	50.00	R0.5	50.04	44.99	-10.0	-10.0	50.00	R0.5	50.07	44.32	-10.0	-7.5
365.00	Overhead Conductors and Devices	50.00	SC	49.88	42.18	-10.1	-10.0	50.00	SC	49.93	43.00	-20.0	-15.9
366.00	Underground Conduit	60.00	L1	59.99	47.99	-10.4	-10.0	60.00	L1	60.04	46.84	-15.0	-11.7
367.00	Underground Conductors and Devices	40.00	L1	39.80	30.52	-9.0	-10.0	40.00	L1	39.90	30.18	-15.0	-12.9
368.00	Line Transformers	55.00	L1	55.07	43.00	-3.7	-5.0	55.00	L1	55.05	42.61	-5.0	-4.3
369.00	Services	55.00	L1	55.36	42.33	-19.8	-20.0	55.00	L1	55.45	42.64	-20.0	-15.7
370.01	Meters - Electronic	20.00	SC	17.52	15.30	0.5		20.00	SC	16.45	14.25		0.0
370.03	Meters - AMI	20.00	SC	20.20	17.79	0.4		15.00	R3	14.87	9.37		0.0
371.00	Installations on Customers' Premises	45.00	L0	44.99	36.69	-14.8	-15.0	45.00	L0	45.07	36.11	-15.0	-13.2
373.00	Street Lighting and Signal Systems	55.00	L0.5	54.49	42.84	-10.5	-12.0	55.00	L0.5	54.53	42.29	-15.0	-12.3
	Total Distribution Plant									42.43	33.13	-12.4	-9.1
	GENERAL PLANT												
	Depreciable												
390.00	Structures and Improvements	40.00	L1	39.90	32.65	-6.6	-5.0	40.00	L1	39.86	33.85	-10.0	-8.5
391.CM	Office Furn. and Equip. - Computer	8.00	L3	7.95	4.77	-0.2		8.00	L3	8.16	4.47		0.0
397.00	Communication Equipment	21.00	L2	21.02	14.54	-0.1		21.00	L2	21.06	13.73		0.0
	Total Depreciable									15.92	10.91	-3.3	-1.1
	Amortizable												
391.FE	Office Furn. and Equip. - Furniture	20.00	SQ	20.00	10.99			20.00	SQ	20.00	9.29		
393.00	Stores Equipment	20.00	SQ	20.00	14.20			20.00	SQ	20.00	14.52		
394.00	Tools, Shop and Garage Equipment	20.00	SQ	20.00	11.54			20.00	SQ	20.00	10.37		
395.00	Laboratory Equipment	20.00	SQ	20.00	9.74			20.00	SQ	20.00	7.16		
398.00	Miscellaneous Equipment	24.00	SQ	24.00	18.64			24.00	SQ	24.00	17.66		
	Total Amortizable									20.62	10.96		
	Total General Plant									16.45	10.92	-2.8	-1.0
	TOTAL UTILITY									32.73	23.11	-8.0	-8.3

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION (by Unit)												
Cholla												
311.00 Structures and Improvements									20.20	6.45	-7.2	
312.00 Boiler Plant Equipment									18.69	6.45	-7.4	
314.00 Turbogenerator Units									20.81	6.45	-7.5	
315.00 Accessory Electric Equipment									25.48	6.44	-7.3	
316.00 Miscellaneous Power Plant Equipment									17.23	6.45	-7.5	
Total Cholla									19.52	6.45	-7.4	
Cholla Unit 1												
311.00 Structures and Improvements	2025	200-SC	23.80	9.38	-8.3	-8.4	2025	200-SC	23.89	6.44	-8.2	-7.7
312.00 Boiler Plant Equipment	2025	200-SC	19.88	9.38	-11.7	-8.7	2025	200-SC	19.18	6.45	-8.4	-8.1
314.00 Turbogenerator Units	2025	200-SC	18.39	9.38	-9.3	-8.6	2025	200-SC	18.42	6.45	-8.4	-8.0
315.00 Accessory Electric Equipment	2025	200-SC	22.99	9.38	-9.0	-8.5	2025	200-SC	23.08	6.45	-8.3	-7.9
316.00 Miscellaneous Power Plant Equipment	2025	200-SC	25.29	9.38	-8.6	-8.6	2025	200-SC	18.93	6.45	-8.4	-7.9
Total Cholla Unit 1									19.39	6.45	-8.4	-8.0
Cholla Unit 3												
311.00 Structures and Improvements	2025	200-SC	20.30	9.38	-6.2	-7.0	2025	200-SC	20.30	6.45	-6.9	-6.4
312.00 Boiler Plant Equipment	2025	200-SC	18.70	9.38	-7.6	-7.4	2025	200-SC	18.24	6.45	-7.1	-6.8
314.00 Turbogenerator Units	2025	200-SC	22.42	9.38	-3.9	-7.2	2025	200-SC	22.21	6.45	-7.1	-6.9
315.00 Accessory Electric Equipment	2025	200-SC	30.24	9.38	-7.1	-7.1	2025	200-SC	30.16	6.44	-7.0	-6.6
316.00 Miscellaneous Power Plant Equipment	2025	200-SC	18.97	9.38	-7.2	-7.2	2025	200-SC	18.06	6.45	-7.1	-6.6
Total Cholla Unit 3									19.64	6.45	-7.1	-6.8
Cholla Common												
311.00 Structures and Improvements	2025	200-SC	20.45	9.38	-6.8	-7.4	2025	200-SC	19.93	6.45	-7.2	-6.8
312.00 Boiler Plant Equipment	2025	200-SC	19.92	9.38	-8.9	-7.7	2025	200-SC	20.01	6.45	-7.5	-7.2
314.00 Turbogenerator Units	2025	200-SC	14.13	9.39	-7.1	-7.6	2025	200-SC	20.15	6.45	-7.4	-7.0
315.00 Accessory Electric Equipment	2025	200-SC	19.82	9.38	-5.2	-7.5	2025	200-SC	17.03	6.45	-7.3	-6.9
316.00 Miscellaneous Power Plant Equipment	2025	200-SC	16.49	9.39	-7.3	-7.6	2025	200-SC	16.45	6.45	-7.4	-7.1
Total Cholla Common									19.36	6.45	-7.4	-7.0

ARIZONA PUBLIC SERVICE COMPANY Statement E

Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
Four Corners												
311.00 Structures and Improvements									29.26	19.01	-10.0	
312.00 Boiler Plant Equipment									26.80	19.01	-11.7	
314.00 Turbogenerator Units									26.95	19.01	-11.5	
315.00 Accessory Electric Equipment									27.51	19.01	-10.4	
316.00 Miscellaneous Power Plant Equipment									29.53	19.01	-10.6	
Total Four Corners									27.05	19.01	-11.5	
Four Corners Units 4-5												
311.00 Structures and Improvements	2038	200-SC	38.42	21.84	-18.6	-19.7	2038	200-SC	33.84	19.00	-11.1	-8.7
312.00 Boiler Plant Equipment	2038	200-SC	42.42	21.83	-19.1	-20.6	2038	200-SC	26.74	19.01	-11.8	-9.6
314.00 Turbogenerator Units	2038	200-SC	40.60	21.83	-19.7	-20.3	2038	200-SC	26.81	19.01	-11.6	-9.4
315.00 Accessory Electric Equipment	2038	200-SC	34.93	21.84	-19.6	-20.0	2038	200-SC	29.84	19.01	-11.3	-9.3
316.00 Miscellaneous Power Plant Equipment	2038	200-SC	35.89	21.84	-20.3	-20.3	2038	200-SC	30.51	19.01	-11.6	-9.8
Total Four Corners Units 4-5									27.11	19.01	-11.7	-9.5
Four Corners Common												
311.00 Structures and Improvements	2038	200-SC	26.79	21.86	-3.1	-11.2	2038	200-SC	23.89	19.02	-8.2	-6.6
312.00 Boiler Plant Equipment	2038	200-SC	30.09	21.85	-12.8	-12.1	2038	200-SC	28.59	19.01	-9.0	-7.4
314.00 Turbogenerator Units	2038	200-SC	37.20	21.84	-8.9	-11.8	2038	200-SC	32.27	19.00	-8.7	-7.1
315.00 Accessory Electric Equipment	2038	200-SC	25.92	21.86	-8.9	-11.5	2038	200-SC	23.75	19.02	-8.5	-7.0
316.00 Miscellaneous Power Plant Equipment	2038	200-SC	34.86	21.84	-11.0	-11.8	2038	200-SC	27.75	19.01	-8.7	-7.5
Total Four Corners Common									26.36	19.01	-8.7	-7.1
NUCLEAR PRODUCTION (by Unit)												
Palo Verde												
321.00 Structures and Improvements									45.35	26.75	-0.4	
322.00 Reactor Plant Equipment									46.35	25.94	-1.0	
323.00 Turbogenerator Units									42.95	26.01	-0.3	
324.00 Accessory Electric Equipment									50.24	25.98	-0.4	
325.00 Miscellaneous Power Plant Equipment									38.90	26.94	-0.4	
Total Palo Verde									45.24	26.28	-0.6	

ARIZONA PUBLIC SERVICE COMPANY

Statement E

Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
Palo Verde Unit 1												
321.00 Structures and Improvements	2044	200-SC	52.70	27.41	-0.5	-0.4	2044	200-SC	50.06	24.63	-0.3	-0.5
322.00 Reactor Plant Equipment	2044	200-SC	47.42	27.43	-1.3	-1.1	2044	200-SC	46.74	24.63	-1.0	-1.1
323.00 Turbogenerator Units	2044	200-SC	45.43	27.43	-1.4	-0.4	2044	200-SC	42.19	24.64	-0.3	-0.5
324.00 Accessory Electric Equipment	2044	200-SC	52.59	27.41	-0.5	-0.4	2044	200-SC	51.10	24.62	-0.3	-0.4
325.00 Miscellaneous Power Plant Equipment	2044	200-SC	49.87	27.41	-1.3	-0.4	2044	200-SC	46.77	24.63	-0.3	-0.5
Total Palo Verde Unit 1									47.04	24.63	-0.6	-0.8
Palo Verde Unit 2												
321.00 Structures and Improvements	2045	200-SC	54.04	28.33	-0.4	-0.4	2045	200-SC	52.67	25.55	-0.4	-0.4
322.00 Reactor Plant Equipment	2045	200-SC	46.16	28.35	-2.3	-1.2	2045	200-SC	45.28	25.57	-1.0	-1.5
323.00 Turbogenerator Units	2045	200-SC	44.59	28.36	-1.1	-0.4	2045	200-SC	42.92	25.57	-0.3	-0.5
324.00 Accessory Electric Equipment	2045	200-SC	52.50	28.34	-0.6	-0.4	2045	200-SC	50.84	25.56	-0.4	-0.4
325.00 Miscellaneous Power Plant Equipment	2045	200-SC	49.51	28.34	-1.1	-0.4	2045	200-SC	48.77	25.56	-0.3	-0.3
Total Palo Verde Unit 2									46.74	25.57	-0.7	-0.9
Palo Verde Unit 3												
321.00 Structures and Improvements	2047	200-SC	53.93	30.17	-0.4	-0.4	2047	200-SC	53.18	27.41	-0.4	-0.6
322.00 Reactor Plant Equipment	2047	200-SC	47.58	30.20	-3.1	-1.2	2047	200-SC	46.77	27.43	-1.1	-1.7
323.00 Turbogenerator Units	2047	200-SC	47.49	30.19	-0.6	-0.4	2047	200-SC	44.00	27.43	-0.4	-0.6
324.00 Accessory Electric Equipment	2047	200-SC	52.54	30.18	-0.7	-0.4	2047	200-SC	51.24	27.41	-0.4	-0.5
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	50.59	30.18	-1.4	-0.4	2047	200-SC	49.39	27.42	-0.4	-0.4
Total Palo Verde Unit 3									47.82	27.42	-0.7	-1.1
Palo Verde Water Reclamation												
321.00 Structures and Improvements	2047	200-SC	41.80	30.22	-1.1	-0.4	2047	200-SC	39.56	27.45	-0.4	-0.5
322.00 Reactor Plant Equipment	2047	200-SC	33.03	30.25	-1.2	-1.2	2047	200-SC	32.04	27.47	-1.1	-1.2
323.00 Turbogenerator Units	2047	200-SC	51.49	30.18	-6.4	-0.4	2047	200-SC	51.39	27.41	-0.4	-0.3
324.00 Accessory Electric Equipment												
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	40.07	30.22	-0.3	-0.4	2047	200-SC	35.63	27.46	-0.4	-0.5
Total Palo Verde Water Reclamation									39.55	27.45	-0.4	-0.5

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
Int Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf
A	B	C	D	E	F	G	H	I	J	K	L	M
Palo Verde Common												
321.00 Structures and Improvements	2047	200-SC	42.59	30.21	-0.8	-0.4	2047	200-SC	40.99	27.44	-0.4	-0.5
322.00 Reactor Plant Equipment	2047	200-SC	45.74	30.20	-10.2	-1.2	2047	200-SC	44.29	27.43	-1.1	-1.6
323.00 Turbogenerator Units	2047	200-SC	35.40	30.24	-4.3	-0.4	2047	200-SC	34.21	27.46	-0.4	-0.3
324.00 Accessory Electric Equipment	2047	200-SC	44.78	30.21	-0.6	-0.4	2047	200-SC	43.28	27.44	-0.4	-0.3
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	37.74	30.23	-1.4	-0.4	2047	200-SC	34.62	27.46	-0.4	-0.4
Total Palo Verde Common									38.72	27.45	-0.5	-0.5
OTHER PRODUCTION												
Combined Cycle												
341.00 Structures and Improvements									28.02	18.39	-5.0	-4.4
342.00 Fuel Holders, Products and Accessories									25.59	14.02	-5.0	-4.2
343.00 Prime Movers									30.91	18.22	-5.0	-4.4
344.00 Generators and Devices									23.57	16.84	-5.0	-4.0
345.00 Accessory Electric Equipment									22.11	14.61	-5.0	-3.6
346.00 Miscellaneous Power Plant Equipment									21.46	15.15	-5.0	-4.0
Total Combined Cycle									25.05	16.87	-5.0	-4.0
Redhawk CC Units 1-2												
341.00 Structures and Improvements	2037	200-SC	30.53	20.91	-4.8	-5.0	2037	200-SC	29.85	18.06	-5.0	-4.3
342.00 Fuel Holders, Products and Accessories	2037	200-SC	25.05	20.92	-5.4	-5.0	2037	200-SC	23.95	18.07	-5.0	-4.2
343.00 Prime Movers	2037	200-SC	31.04	20.90	-8.4	-5.0	2037	200-SC	29.97	18.05	-5.0	-4.3
344.00 Generators and Devices	2037	200-SC	25.53	20.91	11.3	-5.0	2037	200-SC	23.58	18.06	-5.0	-4.3
345.00 Accessory Electric Equipment	2037	200-SC	31.05	20.90	-4.2	-5.0	2037	200-SC	27.20	18.06	-5.0	-4.2
346.00 Miscellaneous Power Plant Equipment	2037	200-SC	24.57	20.92	-3.8	-5.0	2037	200-SC	24.23	18.07	-5.0	-4.4
Total Redhawk CC Units 1-2									25.17	18.06	-5.0	-4.3
West Phoenix												
341.00 Structures and Improvements									27.02	18.58	-5.0	
342.00 Fuel Holders, Products and Accessories									26.39	12.05	-5.0	
343.00 Prime Movers									31.84	18.38	-5.0	
344.00 Generators and Devices									23.56	15.42	-5.0	
345.00 Accessory Electric Equipment									19.82	13.06	-5.0	
346.00 Miscellaneous Power Plant Equipment									20.31	13.94	-5.0	
Total West Phoenix									24.94	15.72	-5.0	

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
ınt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf
A	B	C	D	E	F	G	H	I	J	K	L	M
West Phoenix CC Units 1-3												
341.00 Structures and Improvements	2030	200-SC	25.02	14.23	-4.9	-5.0	2030	200-SC	23.84	11.33	-5.0	-4.6
342.00 Fuel Holders, Products and Accessories	2030	200-SC	25.61	14.23	-5.2	-5.0	2030	200-SC	26.79	11.33	-5.0	-4.7
343.00 Prime Movers												
344.00 Generators and Devices	2030	200-SC	25.17	14.23	-3.4	-5.0	2030	200-SC	20.16	11.33	-5.0	-4.5
345.00 Accessory Electric Equipment	2030	200-SC	19.28	14.23	-6.9	-5.0	2030	200-SC	17.23	11.33	-5.0	-4.5
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	20.85	14.23	-4.8	-5.0	2030	200-SC	18.33	11.33	-5.0	-4.6
Total West Phoenix CC Units 1-3									20.07	11.33	-5.0	-4.5
West Phoenix CC Unit 4												
341.00 Structures and Improvements	2036	200-SC	32.59	19.96	-5.1	-5.0	2036	200-SC	25.36	17.11	-5.0	-4.2
342.00 Fuel Holders, Products and Accessories	2036	200-SC	33.73	19.96	-5.0	-5.0	2036	200-SC	32.60	17.10	-5.0	-4.2
343.00 Prime Movers	2036	200-SC	33.65	19.96	0.6	-5.0	2036	200-SC	33.48	17.10	-5.0	-4.4
344.00 Generators and Devices	2036	200-SC	27.51	19.96	-4.8	-5.0	2036	200-SC	27.29	17.11	-5.0	-4.3
345.00 Accessory Electric Equipment	2036	200-SC	25.84	19.97	-5.0	-5.0	2036	200-SC	23.88	17.11	-5.0	-4.2
346.00 Miscellaneous Power Plant Equipment	2036	200-SC	22.59	19.97	-4.9	-5.0	2036	200-SC	21.46	17.11	-5.0	-4.2
Total West Phoenix CC Unit 4									30.46	17.10	-5.0	-4.3
West Phoenix CC Unit 5												
341.00 Structures and Improvements	2038	200-SC	32.33	21.85	-5.3	-5.0	2038	200-SC	30.89	19.01	-5.0	-4.2
342.00 Fuel Holders, Products and Accessories							2030	200-SC	17.95	11.33	-5.0	-4.6
343.00 Prime Movers	2038	200-SC	31.65	21.85	-6.1	-5.0	2038	200-SC	31.03	19.01	-5.0	-4.2
344.00 Generators and Devices	2038	200-SC	28.72	21.86	5.9	-5.0	2038	200-SC	26.25	19.01	-5.0	-4.1
345.00 Accessory Electric Equipment	2038	200-SC	31.69	21.85	-5.3	-5.0	2038	200-SC	28.84	19.01	-5.0	-4.1
346.00 Miscellaneous Power Plant Equipment	2038	200-SC	25.22	21.86	-5.4	-5.0	2038	200-SC	24.43	19.02	-5.0	-4.1
Total West Phoenix CC Unit 5									27.67	18.91	-5.0	-4.1

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
West Phoenix Common												
341.00 Structures and Improvements	2038	200-SC	32.02	21.85	-7.5	-5.0	2038	200-SC	25.95	19.02	-5.0	-4.1
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices												
345.00 Accessory Electric Equipment												
346.00 Miscellaneous Power Plant Equipment												
Total West Phoenix Common									25.95	19.02	-5.0	-4.1
Combustion Turbine												
341.00 Structures and Improvements									21.51	13.86	-5.0	-4.4
342.00 Fuel Holders, Products and Accessories									33.00	14.76	-5.0	-4.4
343.00 Prime Movers									27.23	16.85	-5.0	-4.1
344.00 Generators and Devices									29.81	27.88	-5.0	-3.8
345.00 Accessory Electric Equipment									27.64	15.78	-5.0	-4.3
346.00 Miscellaneous Power Plant Equipment									24.06	16.56	-5.0	-4.3
Total Combustion Turbine									28.52	22.90	-5.0	-4.5
Douglas CT												
341.00 Structures and Improvements	2030	200-SC	22.02	14.23	-5.0	-5.0	2030	200-SC	22.09	11.33	-5.0	-4.7
342.00 Fuel Holders, Products and Accessories	2030	200-SC	42.08	14.22	-6.4	-5.0	2030	200-SC	42.07	11.32	-5.0	-4.6
343.00 Prime Movers	2030	200-SC	17.14	14.24	-50.6	-5.0	2030	200-SC	17.15	11.33	-5.0	-4.5
344.00 Generators and Devices	2030	200-SC	26.54	14.23	-5.0	-5.0	2030	200-SC	26.61	11.33	-5.0	-4.4
345.00 Accessory Electric Equipment	2030	200-SC	39.59	14.22	-5.9	-5.0	2030	200-SC	23.76	11.33	-5.0	-4.3
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	42.04	14.22	-4.1	-5.0	2030	200-SC	42.09	11.32	-5.0	-4.6
Total Douglas CT									19.35	11.33	-5.0	-4.5
Ocotillo												
341.00 Structures and Improvements									15.79	11.33	-5.0	
342.00 Fuel Holders, Products and Accessories									22.36	11.33	-5.0	
343.00 Prime Movers									18.45	11.33	-5.0	
344.00 Generators and Devices									31.19	30.40	-5.0	
345.00 Accessory Electric Equipment									21.74	11.33	-5.0	
346.00 Miscellaneous Power Plant Equipment									26.73	11.33	-5.0	
Total Ocotillo									30.15	28.80	-5.0	

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
Ocotillo CT Units 1-2												
341.00 Structures and Improvements	2030	200-SC	18.74	14.23	-9.3	-5.0	2030	200-SC	15.79	11.33	-5.0	-4.6
342.00 Fuel Holders, Products and Accessories	2030	200-SC	29.67	14.23	-5.0	-5.0	2030	200-SC	22.36	11.33	-5.0	-4.4
343.00 Prime Movers	2030	200-SC	19.09	14.23	-14.0	-5.0	2030	200-SC	18.45	11.33	-5.0	-4.5
344.00 Generators and Devices	2030	200-SC	22.32	14.23	-5.5	-5.0	2030	200-SC	20.16	11.33	-5.0	-4.5
345.00 Accessory Electric Equipment	2030	200-SC	21.72	14.23	-5.6	-5.0	2030	200-SC	21.74	11.33	-5.0	-4.4
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	25.83	14.23	-4.8	-5.0	2030	200-SC	26.73	11.33	-5.0	-4.4
Total Octillo CT Units 1-2									19.21	11.33	-5.0	-4.5
Ocotillo CT Units 3-7												
341.00 Structures and Improvements												100.0
342.00 Fuel Holders, Products and Accessories												100.0
343.00 Prime Movers												100.0
344.00 Generators and Devices							2051.00	200-SC	31.64	31.18	-5.0	-3.4
345.00 Accessory Electric Equipment												100.0
346.00 Miscellaneous Power Plant Equipment												100.0
Total Octillo CT Units 3-7									31.64	31.18	-5.0	-3.4
Saguaro												
341.00 Structures and Improvements									20.90	11.33	-5.0	
342.00 Fuel Holders, Products and Accessories									34.90	11.32	-5.0	
343.00 Prime Movers									17.65	11.72	-5.0	
344.00 Generators and Devices									23.87	14.27	-5.0	
345.00 Accessory Electric Equipment									21.69	11.88	-5.0	
346.00 Miscellaneous Power Plant Equipment									32.45	11.33	-5.0	
Total Saguaro									21.39	12.94	-5.0	

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
Saguaro CT Units 1-2												
341.00 Structures and Improvements	2030	200-SC	21.68	14.23	-8.8	-5.0	2030	200-SC	20.90	11.33	-5.0	-4.4
342.00 Fuel Holders, Products and Accessories	2030	200-SC	34.85	14.22	-5.7	-5.0	2030	200-SC	34.90	11.32	-5.0	-4.4
343.00 Prime Movers	2030	200-SC	22.10	14.23	-10.7	-5.0	2030	200-SC	17.18	11.33	-5.0	-4.4
344.00 Generators and Devices	2030	200-SC	29.85	14.23	-5.3	-5.0	2030	200-SC	16.22	11.33	-5.0	-4.5
345.00 Accessory Electric Equipment	2030	200-SC	22.02	14.23	-5.9	-5.0	2030	200-SC	21.48	11.33	-5.0	-4.3
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	33.93	14.22	-4.9	-5.0	2030	200-SC	32.45	11.33	-5.0	-4.6
Total Saguaro CT Units 1-2									17.81	11.33	-5.0	-4.4
Saguaro CT Unit 3												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2037	200-SC	25.14	20.92	-5.0	-5.0	2037	200-SC	25.18	18.06	-5.0	-4.3
344.00 Generators and Devices	2037	200-SC	33.69	20.90	-5.1	-5.0	2037	200-SC	33.73	18.05	-5.0	-4.3
345.00 Accessory Electric Equipment	2037	200-SC	33.70	20.90	-5.0	-5.0	2037	200-SC	24.03	18.07	-5.0	-4.2
346.00 Miscellaneous Power Plant Equipment												
Total Saguaro CT Unit 3									32.74	18.05	-5.0	-4.3
Sundance Units 1-10												
341.00 Structures and Improvements	2037	200-SC	29.70	20.91	-6.8	-5.0	2037	200-SC	28.79	18.06	-5.0	-4.3
342.00 Fuel Holders, Products and Accessories	2037	200-SC	29.93	20.91	-5.0	-5.0	2037	200-SC	29.69	18.06	-5.0	-4.3
343.00 Prime Movers	2037	200-SC	30.53	20.91	-5.0	-5.0	2037	200-SC	30.06	18.06	-5.0	-4.2
344.00 Generators and Devices	2037	200-SC	21.85	20.92	-5.0	-5.0	2037	200-SC	21.70	18.07	-5.0	-4.3
345.00 Accessory Electric Equipment	2037	200-SC	30.16	20.91	-5.2	-5.0	2037	200-SC	29.56	18.06	-5.0	-4.3
346.00 Miscellaneous Power Plant Equipment	2037	200-SC	27.86	20.91	-5.0	-5.0	2037	200-SC	21.27	18.07	-5.0	-4.2
Total Sun Dance Units 1-10									29.16	18.06	-5.0	-4.2
West Phoenix CT Units 1-2												
341.00 Structures and Improvements	2030	200-SC	16.66	14.24	-7.7	-5.0	2030	200-SC	16.36	11.33	-5.0	-4.6
342.00 Fuel Holders, Products and Accessories	2030	200-SC	31.39	14.22	-5.0	-5.0	2030	200-SC	30.97	11.33	-5.0	-4.4
343.00 Prime Movers	2030	200-SC	20.27	14.23	-10.0	-5.0	2030	200-SC	20.55	11.33	-5.0	-4.4
344.00 Generators and Devices	2030	200-SC	21.33	14.23	-6.3	-5.0	2030	200-SC	17.28	11.33	-5.0	-4.4
345.00 Accessory Electric Equipment	2030	200-SC	41.82	14.22	-5.1	-5.0	2030	200-SC	28.63	11.33	-5.0	-4.4
346.00 Miscellaneous Power Plant Equipment	2030	200-SC	29.86	14.23	-7.8	-5.0	2030	200-SC	29.90	11.33	-5.0	-4.6
Total West Phoenix CT Units 1-2									19.41	11.33	-5.0	-4.4

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

		Current Parameters						SFAS 143 Method					
		P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
	nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
	A	B	C	D	E	F	G	H	I	J	K	L	M
Yucca													
341.00	Structures and Improvements									18.98	12.55	-5.0	
342.00	Fuel Holders, Products and Accessories									42.38	15.65	-5.0	
343.00	Prime Movers									31.75	21.37	-5.0	
344.00	Generators and Devices									25.89	11.52	-5.0	
345.00	Accessory Electric Equipment									29.64	13.60	-5.0	
346.00	Miscellaneous Power Plant Equipment									27.99	16.80	-5.0	
	Total Yucca									30.08	18.84	-5.0	
Yucca CT Units 1-4													
341.00	Structures and Improvements	2030	200-SC	19.06	14.23	-6.1	-5.0	2030	200-SC	17.72	11.33	-5.0	-4.6
342.00	Fuel Holders, Products and Accessories	2030	200-SC	46.94	14.21	-5.1	-5.0	2030	200-SC	47.16	11.32	-5.0	-4.7
343.00	Prime Movers	2030	200-SC	30.01	14.23	-12.9	-5.0	2030	200-SC	25.97	11.33	-5.0	-4.4
344.00	Generators and Devices	2030	200-SC	26.18	14.23	-6.0	-5.0	2030	200-SC	25.83	11.33	-5.0	-4.5
345.00	Accessory Electric Equipment	2030	200-SC	29.68	14.23	-8.2	-5.0	2030	200-SC	29.75	11.33	-5.0	-4.4
346.00	Miscellaneous Power Plant Equipment	2030	200-SC	33.71	14.22	-5.0	-5.0	2030	200-SC	29.27	11.33	-5.0	-4.4
	Total Yucca CT Units 1-4									25.77	11.33	-5.0	-4.5
Yucca CT Units 5-6													
341.00	Structures and Improvements	2043	200-SC	30.49	26.54	-5.0	-5.0	2043	200-SC	30.53	23.74	-5.0	-4.0
342.00	Fuel Holders, Products and Accessories	2043	200-SC	33.48	26.54	-5.0	-5.0	2043	200-SC	33.47	23.73	-5.0	-3.8
343.00	Prime Movers	2043	200-SC	33.54	26.54	-5.0	-5.0	2043	200-SC	33.11	23.73	-5.0	-3.8
344.00	Generators and Devices	2043	200-SC	32.00	26.54	-5.0	-5.0	2043	200-SC	29.72	23.74	-5.0	-4.2
345.00	Accessory Electric Equipment	2043	200-SC	29.39	26.55	-6.6	-5.0	2043	200-SC	29.14	23.74	-5.0	-4.1
346.00	Miscellaneous Power Plant Equipment	2043	200-SC	27.02	26.55	-5.0	-5.0	2043	200-SC	26.36	23.74	-5.0	-3.8
	Total Yucca CT Units 5-6									32.89	23.73	-5.0	-3.8

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

		Current Parameters						SFAS 143 Method					
		P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
	nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
	A	B	C	D	E	F	G	H	I	J	K	L	M
	Solar Units												
341.00	Structures and Improvements									28.94	23.89	-9.3	
342.00	Fuel Holders, Products and Accessories												
343.00	Prime Movers												
344.00	Generators and Devices									28.64	23.56	-9.7	
345.00	Accessory Electric Equipment									28.54	23.34	-9.5	
346.00	Miscellaneous Power Plant Equipment									29.01	23.89	-9.2	
	Total Solar Units									28.64	23.54	-9.6	
	Chino Valley												
341.05	Structures and Improvements	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-5.9
342.05	Fuel Holders, Products and Accessories												
343.05	Prime Movers												
344.05	Generators and Devices	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-5.9
345.05	Accessory Electric Equipment	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-5.9
346.05	Miscellaneous Power Plant Equipment	2042	200-SC	28.89	25.61	-7.4	-7.4	2042	200-SC	28.93	22.80	-7.4	-5.9
	Total Chino Valley									28.93	22.80	-7.4	-5.9
	Cotton Center												
341.05	Structures and Improvements	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.95	21.86	-6.8	-5.4
342.05	Fuel Holders, Products and Accessories												
343.05	Prime Movers												
344.05	Generators and Devices	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.75	21.86	-6.8	-5.5
345.05	Accessory Electric Equipment	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.95	21.86	-6.8	-5.4
346.05	Miscellaneous Power Plant Equipment	2041	200-SC	28.90	24.68	-6.6	-6.6	2041	200-SC	28.95	21.86	-6.8	-5.4
	Total Cotton Center									28.79	21.86	-6.8	-5.5
	Desert Star												
341.05	Structures and Improvements	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.89	25.61	-10.9	-8.4
342.05	Fuel Holders, Products and Accessories												
343.05	Prime Movers												
344.05	Generators and Devices	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.31	25.62	-10.9	-8.1
345.05	Accessory Electric Equipment	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.89	25.61	-10.9	-8.4
346.05	Miscellaneous Power Plant Equipment	2038	200-SC	22.34	21.87	-11.5	-11.5	2045	200-SC	28.89	25.61	-10.9	-8.4
	Total Desert Star									28.41	25.62	-10.9	-8.2

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
Int Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
Foothills Units												
341.05 Structures and Improvements	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-6.5
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-6.5
345.05 Accessory Electric Equipment	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-6.5
346.05 Miscellaneous Power Plant Equipment	2043	200-SC	28.88	26.55	-8.6	-8.6	2043	200-SC	28.91	23.74	-8.5	-6.5
Total Foothills Units									28.91	23.74	-8.5	-6.5
Gila Bend												
341.05 Structures and Improvements	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-7.8
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-7.8
345.05 Accessory Electric Equipment	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-7.8
346.05 Miscellaneous Power Plant Equipment	2044	200-SC	28.88	27.48	-10.3	-10.3	2044	200-SC	28.90	24.68	-10.3	-7.8
Total Gila Bend									28.90	24.68	-10.3	-7.8
Hyder												
341.05 Structures and Improvements	2042	200-SC	28.74	25.62	-4.4	-4.4	2042	200-SC	28.78	22.80	-4.4	-3.4
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2042	200-SC	28.84	25.61	-4.4	-4.4	2042	200-SC	28.88	22.80	-4.4	-3.4
345.05 Accessory Electric Equipment	2042	200-SC	29.00	25.61	-4.4	-4.4	2042	200-SC	29.04	22.80	-4.4	-3.4
346.05 Miscellaneous Power Plant Equipment	2042	200-SC	29.58	25.61	-4.4	-4.4	2042	200-SC	29.63	22.80	-4.4	-3.4
Total Hyder									28.90	22.80	-4.4	-3.4

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

	Current Parameters						SFAS 143 Method					
	P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
Legacy												
341.00 Structures and Improvements	2037	200-SC	41.95	20.89	-3.9	-5.0	2037	200-SC	40.13	18.05	-0.2	-0.3
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices	2037	200-SC	25.92	20.91	-3.3	-5.0	2037	200-SC	24.94	18.06	-0.2	-0.3
345.00 Accessory Electric Equipment	2037	200-SC	22.73	20.92	-5.2	-5.0	2037	200-SC	22.99	18.07	-0.2	-0.4
346.00 Miscellaneous Power Plant Equipment												
Total Legacy									24.84	18.06	-0.2	-0.3
Luke AFB												
341.05 Structures and Improvements	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-9.9
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-9.9
345.05 Accessory Electric Equipment	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-9.9
346.05 Miscellaneous Power Plant Equipment	2038	200-SC	22.34	21.87	-11.8	-11.8	2045	200-SC	28.89	25.61	-13.0	-9.9
Total Luke AFB									28.89	25.61	-13.0	-9.9
Paloma												
341.05 Structures and Improvements	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.95	21.86	-8.5	-6.7
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.91	21.86	-8.5	-6.9
345.05 Accessory Electric Equipment	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.95	21.86	-8.5	-6.7
346.05 Miscellaneous Power Plant Equipment	2041	200-SC	28.90	24.68	-8.5	-8.5	2041	200-SC	28.95	21.86	-8.5	-6.7
Total Paloma									28.92	21.86	-8.5	-6.8
Red Rock												
341.05 Structures and Improvements	30.00	SQ					2046	200-SC	28.88	26.55	-15.5	-11.3
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2046	200-SC	28.88	26.55	-15.5	-11.3
345.05 Accessory Electric Equipment	30.00	SQ					2046	200-SC	28.88	26.55	-15.5	-11.3
346.05 Miscellaneous Power Plant Equipment							2046	200-SC	28.88	26.55	-15.5	-11.3
Total Redrock									28.88	26.55	-15.5	-11.3

ARIZONA PUBLIC SERVICE COMPANY
Parameter Summary - SFAS 143 Method
With Redistribution
Accretion Rate: 3.78 Percent

Statement E

		Current Parameters						SFAS 143 Method					
		P-Life/	Curve	VG	Rem.	Avg.	Fut.	P-Life/	Curve	VG	Rem.	Fut. Net Sal.	
	nt Description	AYFR	Shape	ASL	Life	Sal.	Sal.	AYFR	Shape	ASL	Life	Sf	Sf'
	A	B	C	D	E	F	G	H	I	J	K	L	M
	Roof Tops												
341.05	Structures and Improvements	2042	200-SC	28.71	25.62	-5.0	-5.0	2042	200-SC	28.73	22.80	-16.8	-13.4
342.05	Fuel Holders, Products and Accessories												
343.05	Prime Movers												
344.05	Generators and Devices	2042	200-SC	28.58	25.62	-5.0	-5.0	2042	200-SC	27.52	22.80	-16.9	-13.0
345.05	Accessory Electric Equipment	2042	200-SC	28.62	25.62	-5.0	-5.0	2042	200-SC	26.90	22.80	-16.9	-13.2
346.05	Miscellaneous Power Plant Equipment												
	Total Roof Tops									27.42	22.80	-16.9	-13.1

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the APS depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 367.00 – UG Conductors and Devices. Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the APS study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column C) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the observed proportions surviving and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

Schedule A
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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant
Account: 367.00 UG Conductors and Devices

Dispersion: 40 - L1
Procedure: Vintage Group

Generation Arrangement

	December 31, 2018				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2018	0.5	115,928,337	40.00	39.53	0.9882	1.0000	114,564,350	2,898,188
2017	1.5	89,776,561	40.00	38.60	0.9650	1.0000	86,631,029	2,244,305
2016	2.5	79,541,558	40.00	37.69	0.9421	1.0000	74,937,775	1,988,319
2015	3.5	88,101,080	40.01	36.80	0.9197	1.0000	81,027,196	2,201,947
2014	4.5	55,991,952	40.01	35.93	0.8980	1.0000	50,283,133	1,399,512
2013	5.5	44,319,538	40.01	35.08	0.8768	1.0000	38,858,885	1,107,584
2012	6.5	49,182,474	40.01	34.27	0.8565	1.0000	42,122,902	1,229,311
2011	7.5	45,668,031	40.03	33.47	0.8362	1.0000	38,187,572	1,140,829
2010	8.5	52,382,948	40.01	32.71	0.8175	1.0000	42,820,712	1,309,104
2009	9.5	50,285,111	40.08	31.98	0.7978	1.0000	40,117,866	1,254,656
2008	10.5	84,664,653	40.01	31.27	0.7816	1.0000	66,171,930	2,116,133
2007	11.5	113,250,438	40.04	30.60	0.7641	1.0000	86,531,847	2,828,277
2006	12.5	108,013,234	39.97	29.95	0.7493	1.0000	80,932,115	2,702,230
2005	13.5	82,306,918	40.09	29.33	0.7317	1.0000	60,220,361	2,052,883
2004	14.5	62,864,800	40.07	28.75	0.7175	1.0000	45,106,897	1,569,038
2003	15.5	55,742,585	40.18	28.19	0.7016	1.0000	39,109,869	1,387,372
2002	16.5	56,841,901	40.13	27.66	0.6892	1.0000	39,174,414	1,416,352
2001	17.5	68,784,915	40.30	27.15	0.6738	1.0000	46,349,284	1,706,950
2000	18.5	59,004,425	40.11	26.67	0.6649	1.0000	39,234,648	1,471,031
1999	19.5	51,754,779	40.22	26.21	0.6517	1.0000	33,731,160	1,286,856
1998	20.5	63,670,783	40.70	25.77	0.6332	1.0000	40,315,717	1,564,325
1997	21.5	41,153,737	40.62	25.35	0.6240	1.0000	25,681,363	1,013,113
1996	22.5	40,825,581	40.52	24.94	0.6156	1.0000	25,130,869	1,007,642
1995	23.5	30,174,430	38.37	24.54	0.6397	1.0000	19,301,714	786,465
1994	24.5	25,515,224	40.45	24.15	0.5970	1.0000	15,233,436	630,735
1993	25.5	28,577,078	40.76	23.77	0.5831	1.0000	16,662,094	701,066
1992	26.5	35,849,128	40.61	23.39	0.5759	1.0000	20,645,990	882,790
1991	27.5	21,039,244	40.28	23.01	0.5713	1.0000	12,019,812	522,309
1990	28.5	35,962,062	39.57	22.64	0.5723	1.0000	20,580,285	908,884
1989	29.5	24,805,058	38.56	22.28	0.5778	1.0000	14,333,592	643,368
1988	30.5	15,398,447	35.72	21.92	0.6136	1.0000	9,448,933	431,070
1987	31.5	10,478,520	34.81	21.57	0.6195	1.0000	6,491,362	301,011
1986	32.5	7,046,335	34.09	21.22	0.6224	1.0000	4,385,657	206,721
1985	33.5	11,774,383	36.39	20.87	0.5736	1.0000	6,753,259	323,581
1984	34.5	7,578,560	36.17	20.53	0.5676	1.0000	4,301,347	209,518
1983	35.5	4,016,585	37.10	20.19	0.5442	1.0000	2,185,925	108,249
1982	36.5	4,237,459	36.83	19.86	0.5393	1.0000	2,285,468	115,068

Schedule A
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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant
Account: 367.00 UG Conductors and Devices

Dispersion: 40 - L1
Procedure: Vintage Group

Generation Arrangement

	December 31, 2018				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1981	37.5	6,576,836	37.07	19.53	0.5269	1.0000	3,465,236	177,393
1980	38.5	4,168,091	36.14	19.21	0.5315	1.0000	2,215,515	115,326
1979	39.5	2,085,631	34.24	18.89	0.5517	1.0000	1,150,649	60,907
1978	40.5	2,710,323	35.86	18.58	0.5180	1.0000	1,404,069	75,583
1977	41.5	1,739,149	35.63	18.27	0.5126	1.0000	891,444	48,805
1976	42.5	1,408,861	37.12	17.96	0.4837	1.0000	681,512	37,950
1975	43.5	1,913,122	36.32	17.65	0.4861	1.0000	930,019	52,679
1974	44.5	1,075,103	35.43	17.35	0.4898	1.0000	526,560	30,341
1973	45.5	1,118,027	37.21	17.06	0.4585	1.0000	512,599	30,049
1972	46.5	1,138,244	34.69	16.77	0.4833	1.0000	550,097	32,811
1971	47.5	604,374	31.54	16.48	0.5225	1.0000	315,758	19,164
1970	48.5	3,495,929	43.46	16.19	0.3726	1.0000	1,302,509	80,448
1969	49.5	921,931	40.01	15.91	0.3976	1.0000	366,544	23,041
1968	50.5	1,913,256	45.51	15.63	0.3434	1.0000	657,055	42,040
1967	51.5	2,773,570	49.75	15.35	0.3086	1.0000	855,966	55,750
1966	52.5	770,834	46.30	15.08	0.3257	1.0000	251,085	16,649
1965	53.5	1,254,580	47.85	14.81	0.3095	1.0000	388,345	26,220
1964	54.5	1,281,470	44.39	14.54	0.3277	1.0000	419,899	28,870
1963	55.5	299,302	43.05	14.28	0.3317	1.0000	99,277	6,952
1962	56.5	1,121	29.51	14.02	0.4751	1.0000	533	38
1961	57.5	2,460,867	47.33	13.76	0.2908	1.0000	715,566	51,997
1960	58.5	47,899	39.68	13.51	0.3404	1.0000	16,305	1,207
1958	60.5	38,448	43.44	13.00	0.2993	1.0000	11,509	885
1956	62.5	1,545,619	51.69	12.51	0.2421	1.0000	374,133	29,900
Total	13.8	$1,863,851,442	39.90	30.18	0.7565	1.0000	$1,409,972,953	$46,711,795

Schedule B
Page 1 of 2

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2018	Derived Additions	1971 Opening Balance	Experience to 12/31/2018		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2018	0.5	115,931,352		115,928,337	1.0000	0.5000
2017	1.5	89,777,723		89,776,561	1.0000	1.5000
2016	2.5	79,737,395		79,541,558	0.9975	2.4988
2015	3.5	88,219,506		88,101,080	0.9987	3.4986
2014	4.5	56,476,841		55,991,952	0.9914	4.4867
2013	5.5	44,678,425		44,319,538	0.9920	5.4796
2012	6.5	50,073,020		49,182,474	0.9822	6.4549
2011	7.5	46,225,296		45,668,031	0.9879	7.4535
2010	8.5	53,372,687		52,382,948	0.9815	8.4071
2009	9.5	50,856,520		50,285,111	0.9888	9.4339
2008	10.5	86,995,509		84,664,653	0.9732	10.3181
2007	11.5	116,384,192		113,250,438	0.9731	11.2957
2006	12.5	112,275,537		108,013,234	0.9620	12.1595
2005	13.5	85,058,914		82,306,918	0.9676	13.2036
2004	14.5	65,733,719		62,864,800	0.9564	14.0863
2003	15.5	58,498,509		55,742,585	0.9529	15.0957
2002	16.5	60,090,306		56,841,901	0.9459	15.9322
2001	17.5	72,629,306		68,784,915	0.9471	16.9637
2000	18.5	63,846,698		59,004,425	0.9242	17.6288
1999	19.5	57,254,837		51,754,779	0.9039	18.5702
1998	20.5	67,935,430		63,670,783	0.9372	19.8711
1997	21.5	45,945,520		41,153,737	0.8957	20.5896
1996	22.5	46,132,607		40,825,581	0.8850	21.2656
1995	23.5	39,198,296		30,174,430	0.7698	19.8793
1994	24.5	30,532,870		25,515,224	0.8357	22.7093
1993	25.5	32,818,292		28,577,078	0.8708	23.7439
1992	26.5	44,521,099		35,849,128	0.8052	24.2972
1991	27.5	28,788,635		21,039,244	0.7308	24.6577
1990	28.5	52,677,451		35,962,062	0.6827	24.6134
1989	29.5	44,455,312		24,805,058	0.5580	24.2523
1988	30.5	40,865,800		15,398,447	0.3768	22.0516
1987	31.5	30,924,071		10,478,520	0.3388	21.7557
1986	32.5	21,795,900		7,046,335	0.3233	21.6272
1985	33.5	24,808,329		11,774,383	0.4746	24.5069
1984	34.5	17,735,429		7,578,560	0.4273	24.8511
1983	35.5	8,745,998		4,016,585	0.4592	26.3271
1982	36.5	9,391,181		4,237,459	0.4512	26.5727
1981	37.5	13,919,669		6,576,836	0.4725	27.3296

Schedule B
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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2018	Derived Additions	1971 Opening Balance	Experience to 12/31/2018 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1980	38.5	10,300,233		4,168,091	0.4047	26.8867
1979	39.5	6,639,570		2,085,631	0.3141	25.4610
1978	40.5	6,975,826		2,710,323	0.3885	27.5339
1977	41.5	4,440,551		1,739,149	0.3917	27.7494
1976	42.5	3,277,478		1,408,861	0.4299	29.6623
1975	43.5	5,492,574		1,913,122	0.3483	29.2627
1974	44.5	2,968,554		1,075,103	0.3622	28.7712
1973	45.5	2,820,657		1,118,027	0.3964	30.9201
1972	46.5	3,877,951		1,138,244	0.2935	28.7656
1971	47.5	2,578,631		604,374	0.2344	25.9575
1970	48.5		7,023,065	3,495,929	0.4978	38.2079
1969	49.5		1,968,869	921,931	0.4683	35.0817
1968	50.5		3,241,505	1,913,256	0.5902	40.8829
1967	51.5		3,838,902	2,773,570	0.7225	45.4114
1966	52.5		1,378,728	770,834	0.5591	42.2354
1965	53.5		2,643,892	1,254,580	0.4745	44.0488
1964	54.5		3,507,482	1,281,470	0.3654	40.8377
1963	55.5		1,017,190	299,302	0.2942	39.7422
1962	56.5		128,232	1,121	0.0087	26.4262
1961	57.5		6,995,617	2,460,867	0.3518	44.4563
1960	58.5		264,023	47,899	0.1814	37.0096
1959	59.5		93,968		0.0000	30.4671
1958	60.5		190,948	38,448	0.2014	41.1503
1957	61.5		67,204		0.0000	28.9379
1956	62.5		4,023,015	1,545,619	0.3842	49.7315
1955	63.5		122,718		0.0000	33.2093
1954	64.5		19,062		0.0000	31.2236
1953	65.5		15,400		0.0000	34.1003
1952	66.5		14,699		0.0000	33.4659
1951	67.5		4,289		0.0000	35.6181
1950	68.5		10,233		0.0000	44.0000
1946	72.5		8,447		0.0000	48.0000
1940	78.5		4,926		0.0000	42.7389
Total	13.8	$2,104,680,207	$36,582,414	$1,863,851,442	0.8704	

Schedule C
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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	11,234,859	5,227,485			16,462,344
1972	16,462,344	5,626,788	167,216		21,921,916
1973	21,921,916	5,899,426	110,107		27,711,235
1974	27,711,235	6,605,495	72,619		34,244,111
1975	34,244,111	4,188,877	143,093		38,289,895
1976	38,289,895	4,904,543	119,194	196	43,075,440
1977	43,075,440	7,682,950	62,687	135	50,695,839
1978	50,695,839	6,255,514	144,347	223	56,807,229
1979	56,807,229	12,165,882	180,100	338	68,793,348
1980	68,793,348	11,925,816	261,221	6,573	80,464,517
1981	80,464,517	13,706,676	311,535	(182)	93,859,475
1982	93,859,475	12,677,752	280,423		106,256,805
1983	106,256,805	12,220,047	167,539	27	118,309,340
1984	118,309,340	24,564,892	620,234	(711,901)	141,542,097
1985	141,542,097	28,119,927	588,413	100,773	169,174,384
1986	169,174,384	33,086,796	776,947	(819,083)	200,665,150
1987	200,665,150	40,442,295	1,411,693	11,977	239,707,730
1988	239,707,730	44,562,290	1,298,863	(102,165)	282,868,992
1989	282,868,992	39,930,190	1,822,189	1,230,377	322,207,369
1990	322,207,369	48,232,643	2,081,398	(242,515)	368,116,099
1991	368,116,099	26,258,331	6,505,011	(35,194)	387,834,225
1992	387,834,225	43,961,641	7,676,820	(25,026,623)	399,092,424
1993	399,092,424	32,825,279	12,346,537	(323,901)	419,247,265
1994	419,247,265	30,533,944	6,133,313	385,837	444,033,733
1995	444,033,733	39,423,523	5,497,824		477,959,432
1996	477,959,432	46,015,566	2,560,192		521,414,806
1997	521,414,806	45,962,909	8,905,235	(37,625)	558,434,855
1998	558,434,855	67,536,428	21,756,216		604,215,067
1999	604,215,067	57,369,075	9,569,466		652,014,675
2000	652,014,675	63,360,845	10,611,085		704,764,435
2001	704,764,435	51,081,906	10,079,147		745,767,195
2002	745,767,195	69,400,154	13,144,993		802,022,355
2003	802,022,355	60,001,037	12,088,891		849,934,501
2004	849,934,501	74,271,162	15,315,290		908,890,373
2005	908,890,373	91,985,491	7,426,563	379,484	993,828,785
2006	993,828,785	123,918,259	8,664,638	429	1,109,082,836
2007	1,109,082,836	134,150,439	10,281,509	1,872,293	1,234,824,060
2008	1,234,824,060	94,814,104	9,083,916	(95,633)	1,320,458,614
2009	1,320,458,614	62,492,252	11,733,105	202,017	1,371,419,778
2010	1,371,419,778	58,927,725	7,660,141	21,140	1,422,708,502

Schedule C
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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2011	1,422,708,502	43,524,346	9,210,495	(44,497)	1,456,977,856
2012	1,456,977,856	47,222,515	9,583,537	36,067	1,494,652,901
2013	1,494,652,901	53,730,829	6,521,014	115,062	1,541,977,778
2014	1,541,977,778	54,477,481	8,392,283	(984,094)	1,587,078,882
2015	1,587,078,882	69,029,324	9,727,135		1,646,381,070
2016	1,646,381,070	37,260,209	9,013,566		1,674,627,713
2017	1,674,627,713	82,202,162	8,170,347	(315,216)	1,748,344,312
2018	1,748,344,312	124,631,106	9,133,092	9,116	1,863,851,442

Schedule C
Page 1 of 2

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	11,081,927	5,227,485			16,309,412
1972	16,309,412	6,221,813	167,216		22,364,009
1973	22,364,009	6,947,551	109,802		29,201,758
1974	29,201,758	5,440,303	71,744		34,570,317
1975	34,570,317	3,856,115	143,398		38,283,034
1976	38,283,034	4,856,897	108,092	196	43,032,035
1977	43,032,035	5,547,742	73,789	135	48,506,123
1978	48,506,123	9,535,737	144,905	223	57,897,178
1979	57,897,178	11,431,460	180,100	338	69,148,876
1980	69,148,876	12,365,001	261,538	6,573	81,258,911
1981	81,258,911	13,176,167	311,535	(182)	94,123,362
1982	94,123,362	12,706,417	280,423		106,549,356
1983	106,549,356	13,043,237	165,751	27	119,426,869
1984	119,426,869	21,961,759	617,304	(711,901)	140,059,423
1985	140,059,423	24,635,568	591,343	100,773	164,204,421
1986	164,204,421	33,744,143	773,965	(819,083)	196,355,516
1987	196,355,516	32,889,905	1,408,643	11,977	227,848,755
1988	227,848,755	43,251,756	1,217,615	(102,165)	269,780,732
1989	269,780,732	49,842,853	1,833,911	1,230,377	319,020,051
1990	319,020,051	46,937,808	2,081,042	(242,515)	363,634,302
1991	363,634,302	36,843,350	6,580,659	(35,194)	393,861,799
1992	393,861,799	38,584,248	7,675,544	(25,026,623)	399,743,881
1993	399,743,881	32,821,128	12,345,547	(323,901)	419,895,561
1994	419,895,561	30,543,844	6,132,492	385,837	444,692,750
1995	444,692,750	39,205,414	5,497,343		478,400,821
1996	478,400,821	46,131,701	2,559,267		521,973,255
1997	521,973,255	45,947,957	8,902,760	(37,625)	558,980,827
1998	558,980,827	67,627,089	21,754,729		604,853,187
1999	604,853,187	57,258,250	9,560,988		652,550,449
2000	652,550,449	64,090,317	10,610,781		706,029,985
2001	706,029,985	72,357,910	10,078,436		768,309,459
2002	768,309,459	59,838,811	13,144,764		815,003,506
2003	815,003,506	57,985,224	12,111,789		860,876,940
2004	860,876,940	65,576,468	15,353,546		911,099,862
2005	911,099,862	84,783,460	7,750,593	379,484	988,512,213
2006	988,512,213	111,975,768	8,299,685	429	1,092,188,725
2007	1,092,188,725	116,329,725	10,281,509	1,871,806	1,200,108,747
2008	1,200,108,747	86,977,752	9,083,916	(95,633)	1,277,906,950
2009	1,277,906,950	50,856,520	11,733,105	202,017	1,317,232,382
2010	1,317,232,382	53,243,383	7,660,141	21,140	1,362,836,764

Schedule C
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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2011	1,362,836,764	46,234,494	9,210,495	(44,497)	1,399,816,265
2012	1,399,816,265	50,893,443	9,583,537	36,067	1,441,162,238
2013	1,441,162,238	44,678,425	6,521,014	115,062	1,479,434,711
2014	1,479,434,711	56,476,841	8,392,283	(984,094)	1,526,535,176
2015	1,526,535,176	88,219,506	9,727,135		1,605,027,547
2016	1,605,027,547	79,737,926	9,013,566		1,675,751,907
2017	1,675,751,907	89,777,723	8,170,347	(315,216)	1,757,044,066
2018	1,757,044,066	115,931,352	9,133,092	9,116	1,863,851,442

Schedule D
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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-1975	66.0	51.3	L0.5	2.57	47.6	L1	2.83	36.7	R2	4.43
1972-1976	67.4	55.1	L0.5	2.60	52.3	L1	2.68	41.0	R1.5	3.26
1973-1977	82.2	75.6	L0.5	2.10	145.1	SC *	1.42	49.5	R2	2.42
1974-1978	81.4	73.2	L0.5	1.94	141.4	SC *	1.13	51.5	R2	2.10
1975-1979	71.5	59.3	L1	1.61	53.4	L1.5	2.30	113.1	O3 *	1.83
1976-1980	66.2	55.5	L1	1.97	45.3	S0.5	4.31	138.6	SC *	2.03
1977-1981	50.2	48.2	L1 *	2.58	37.8	S1	5.90	104.9	O4 *	2.95
1978-1982	44.7	46.3	L1.5 *	2.81	36.1	S1	7.05	103.7	O4 *	3.16
1979-1983	48.1	49.3	L1.5 *	2.62	38.1	S1	7.43	118.0	SC *	3.47
1980-1984	27.2	45.7	L1.5 *	7.23	33.8	S1.5	6.44	63.2	O4 *	3.14
1981-1985	23.0	45.6	L1.5 *	8.16	33.5	S1.5	6.97	44.6	L1.5 *	4.28
1982-1986	21.1	46.2	L1.5 *	8.71	34.0	S1.5	6.53	34.7	S1.5	5.46
1983-1987	13.3	45.1	L1 *	11.96	32.6	S1.5	5.11	32.5	S1.5	5.19
1984-1988	13.1	44.7	L1	10.48	33.2	S1.5	5.16	32.8	S1.5	5.75
1985-1989	16.8	44.1	L1	7.51	34.9	S1	4.21	34.0	R2	5.53
1986-1990	5.1	41.4	L1	9.31	33.4	S1	2.78	32.5	R2	4.23
1987-1991	4.6	43.8	L0	10.67	34.8	R1	3.32	31.1	R2	7.23
1988-1992	0.4	34.7	L0.5	13.06	92.3	O4 *	20.15	103.2	O4 *	22.85
1989-1993	0.8	27.3	L0.5	6.54	79.8	O4 *	16.22	78.3	O4 *	15.75
1990-1994	0.0	27.3	L0.5	8.31	76.0	O4 *	16.34	72.8	O4 *	15.27
1991-1995	0.0	27.8	L0.5	9.71	74.0	O4 *	15.84	69.5	O4 *	14.26
1992-1996	0.0	30.3	L0.5	12.57	79.4	O4 *	16.72	73.8	O4 *	14.84
1993-1997	0.0	29.6	L1	8.88	54.7	O4 *	10.33	64.8	O4 *	12.11
1994-1998	0.0	25.7	L1.5 *	4.11	26.0	S0.5	3.25	26.7	R1.5	3.40
1995-1999	0.0	26.0	L1.5 *	4.65	26.0	S0.5	3.37	26.6	R1.5	2.57
1996-2000	5.5	26.2	L1.5 *	5.40	26.0	S0.5	4.32	26.4	R1	3.03
1997-2001	5.8	25.9	L1.5 *	5.13	25.6	S0.5	4.59	25.8	S0	3.66
1998-2002	10.9	26.5	L1 *	4.22	26.4	L1	4.29	26.4	L1	4.26
1999-2003	46.1	33.3	L0.5	10.40	95.4	O4 *	3.85	90.8	O4 *	5.34
2000-2004	34.3	32.2	L0.5	9.15	86.6	O4 *	3.36	81.1	O4 *	4.93
2001-2005	25.2	34.2	L0.5	8.17	89.1	O4 *	3.80	85.5	O4 *	5.08
2002-2006	42.4	36.6	L1	8.26	94.0	O4 *	3.14	91.4	O4 *	4.72
2003-2007	44.1	39.6	L1	7.07	94.2	O4 *	3.08	95.4	O4 *	4.64
2004-2008	46.3	41.8	L1	6.83	93.9	O4 *	3.14	99.4	O4 *	4.43
2005-2009	5.1	45.1	L1	7.37	94.9	O4 *	6.16	105.1	O4 *	7.27
2006-2010	20.1	46.5	L1	6.24	85.0	O4 *	4.61	105.5	O4 *	5.82
2007-2011	48.1	46.7	L1	6.91	85.4	O4 *	4.17	104.6	O4 *	5.16
2008-2012	0.0	47.9	L1 *	7.55	86.4	O4 *	6.54	106.1	O4 *	7.50

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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2009-2013	53.9	50.1	L1.5 *	6.09	89.1	O4 *	3.71	109.7	O4 *	4.14
2010-2014	55.2	53.0	L1.5 *	5.49	81.4	O3 *	3.84	113.4	O3 *	3.53
2011-2015	57.0	52.3	L1.5 *	7.34	85.9	O4 *	5.07	111.4	O3 *	5.36
2012-2016	55.7	53.0	L1.5 *	7.03	72.2	O3 *	5.32	110.5	O3 *	5.25
2013-2017	56.4	54.8	L1.5 *	6.65	67.8	O2 *	5.24	113.4	O3 *	4.67
2014-2018	54.0	55.3	L1.5 *	5.84	62.6	L0.5 *	4.74	113.0	O3 *	3.69

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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None

Placement Band: 1940-2018

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	39.8	44.0	L1	6.04	66.1	O4 *	3.54	93.7	O4 *	1.12
1973-2018	39.8	44.0	L1	6.04	66.2	O4 *	3.54	93.7	O4 *	1.12
1975-2018	39.8	44.0	L1	6.04	66.2	O4 *	3.54	93.7	O4 *	1.12
1977-2018	39.8	44.0	L1	6.04	66.2	O4 *	3.54	93.7	O4 *	1.12
1979-2018	39.8	43.9	L1	6.04	66.3	O4 *	3.53	93.7	O4 *	1.12
1981-2018	39.8	43.9	L1	6.03	66.3	O4 *	3.53	93.7	O4 *	1.13
1983-2018	39.8	43.9	L1	6.02	66.4	O4 *	3.52	93.7	O4 *	1.12
1985-2018	39.8	43.9	L1	6.02	66.6	O4 *	3.51	93.7	O4 *	1.12
1987-2018	39.8	43.9	L1	6.01	66.9	O4 *	3.49	93.6	O4 *	1.12
1989-2018	39.8	43.9	L1	6.01	67.5	O4 *	3.46	93.7	O4 *	1.11
1991-2018	39.8	44.0	L1	6.00	67.8	O4 *	3.44	93.7	O4 *	1.12
1993-2018	40.0	44.2	L1	6.07	68.3	O4 *	3.48	94.2	O4 *	1.13
1995-2018	40.3	45.0	L1	5.78	61.1	O3 *	3.84	94.6	O4 *	1.18
1997-2018	40.0	45.1	L1	5.63	58.0	O3 *	3.94	93.9	O4 *	1.19
1999-2018	50.6	48.6	L1	7.99	99.3	O4 *	3.28	109.0	O4 *	2.72
2001-2018	50.9	49.3	L1	7.75	94.9	O4 *	3.72	108.9	O4 *	3.00
2003-2018	51.4	50.5	L1 *	7.25	86.5	O4 *	4.20	109.4	O4 *	3.19
2005-2018	52.6	52.4	L1 *	6.72	76.3	O3 *	4.56	111.4	O3 *	3.28
2007-2018	53.2	52.7	L1.5 *	6.85	74.9	O3 *	4.79	111.3	O3 *	3.59
2009-2018	53.5	53.4	L1.5 *	6.62	72.7	O3 *	4.77	111.9	O3 *	3.56
2011-2018	55.9	54.6	L1.5 *	6.99	74.4	O3 *	5.14	113.8	O3 *	4.38
2013-2018	55.7	55.7	L1.5 *	6.29	65.5	L0.5 *	5.02	114.6	O3 *	4.02
2015-2018	53.2	55.4	L1.5 *	5.55	60.5	L1 *	4.62	112.4	O3 *	3.54
2017-2018	54.0	59.3	L1.5 *	4.14	63.7	L1 *	3.68	119.6	SC *	1.61

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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-1972	66.4	44.2	L0.5	3.54	32.0	S1	8.19	29.7	R2	9.75
1971-1974	71.2	55.2	L0.5	3.05	43.0	S0.5	4.53	36.8	R2	5.74
1971-1976	68.2	57.6	L0.5	2.48	55.7	L1	2.49	40.6	R2	3.15
1971-1978	67.7	69.5	L0.5	3.33	54.7	S0.5	2.45	73.1	O3 *	2.59
1971-1980	53.1	56.3	L1	4.85	44.0	S0.5	1.75	115.6	O3 *	3.18
1971-1982	37.5	50.3	L1	7.51	37.7	S1	1.69	79.8	O4 *	2.61
1971-1984	25.5	48.8	L1 *	9.21	35.4	S1.5	3.22	42.1	L2 *	1.88
1971-1986	16.7	47.7	L1 *	11.03	34.9	S1.5	2.86	35.2	S1.5	2.56
1971-1988	10.0	46.9	L1	13.11	34.5	S1.5	2.08	34.3	S1.5	2.19
1971-1990	2.5	43.4	L1 *	13.58	33.8	S1	1.90	33.5	S1.5	1.51
1971-1992	0.9	38.1	L0.5	13.77	39.1	L0.5	14.40	107.6	O4 *	21.74
1971-1994	0.0	31.5	L1	8.23	87.7	O4 *	17.74	92.4	O4 *	19.17
1971-1996	0.0	33.7	L1	10.00	96.0	O4 *	18.98	94.3	O4 *	18.51
1971-1998	0.0	27.4	L1.5 *	4.19	26.9	S0.5	3.50	27.2	S0.5	3.11
1971-2000	0.0	28.3	L1 *	3.79	27.9	L1.5	3.40	27.8	S0	2.91
1971-2002	0.0	29.0	L1	4.15	29.2	L1	4.30	31.1	L1 *	4.54
1971-2004	0.0	29.5	L1	3.47	31.6	L0.5 *	3.50	53.8	O4 *	5.19
1971-2006	0.0	31.6	L1	4.19	36.9	L0.5 *	3.15	62.1	O4 *	3.82
1971-2008	0.0	33.4	L1	4.49	43.8	O3 *	3.35	69.7	O4 *	4.16
1971-2010	7.8	35.2	L1	4.31	48.4	O3 *	2.89	74.8	O4 *	3.47
1971-2012	0.0	37.2	L1	5.43	56.2	O4 *	4.04	80.6	O4 *	4.52
1971-2014	36.1	39.7	L1	5.43	62.7	O4 *	2.87	86.7	O4 *	1.36
1971-2016	37.4	41.6	L1	5.70	62.4	O4 *	3.30	89.4	O4 *	1.13
1971-2018	39.8	44.0	L1	6.04	66.1	O4 *	3.54	93.7	O4 *	1.12

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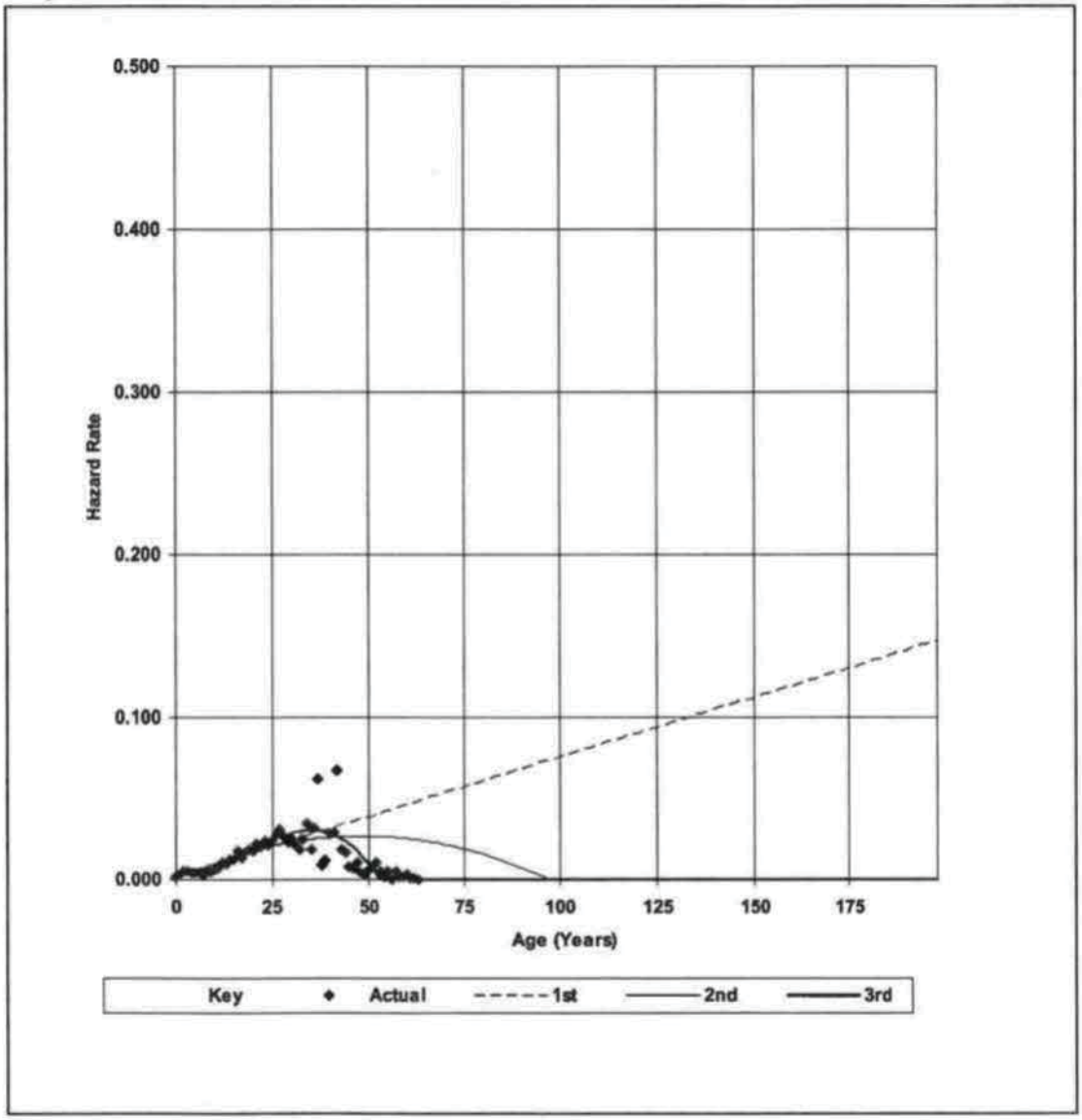
ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2018 Observation Band: 1971-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Functions 1st: 44.0-L1 2nd: 66.1-O4 3rd: 93.7-O4



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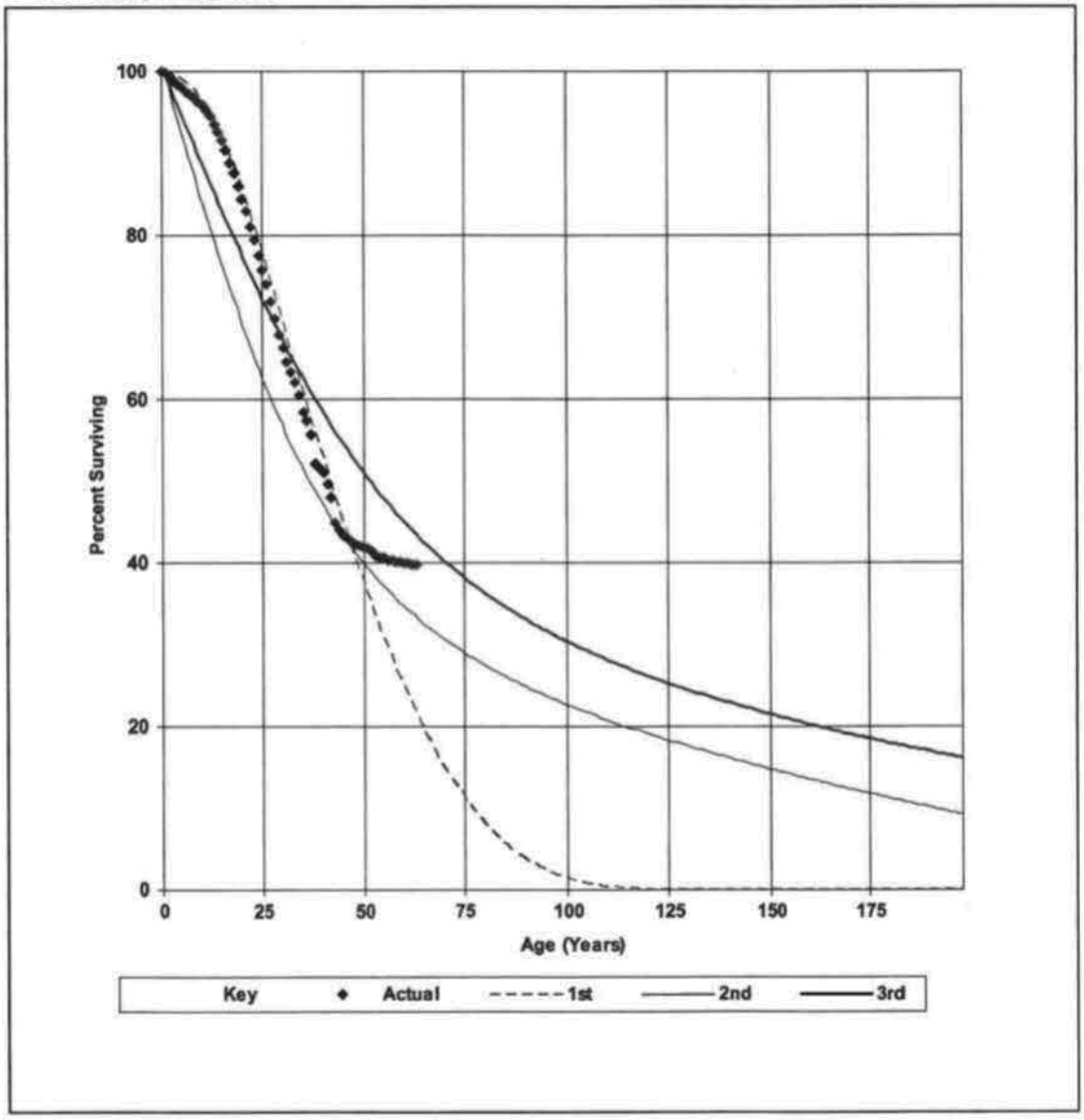
ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2018 Observation Band: 1971-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Survivorship Functions 1st: 44.0-L1 2nd: 66.1-O4 3rd: 93.7-O4



Schdule E
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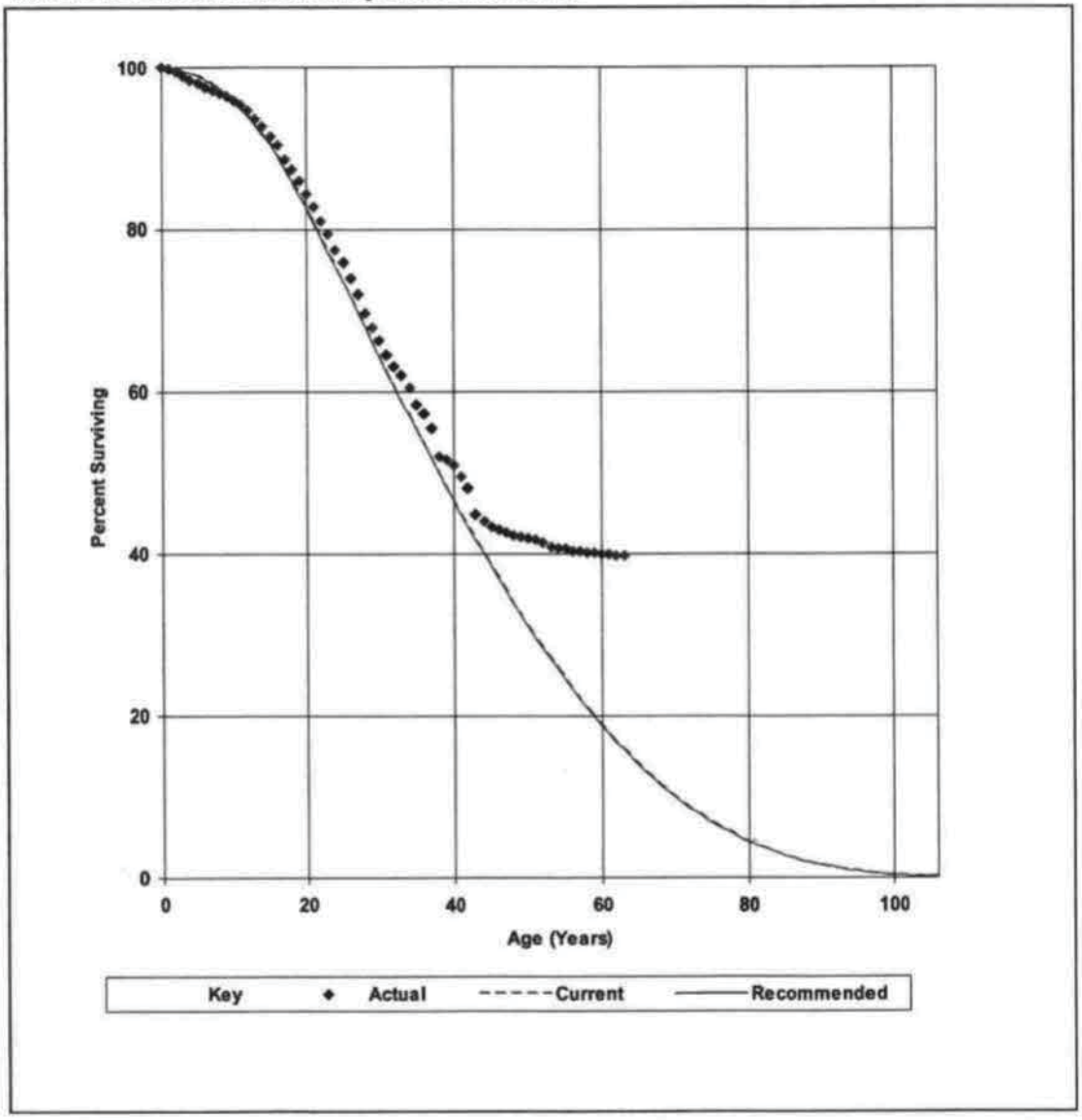
ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2018
Observation Band: 1971-2018

Current and Recommended Projection Life Curves Current: 40.0-L1 Recommended: 40.0-L1



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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1993	12,346,537	2,524,434	20.4		1,610,244	13.0		914,190	7.4	
1994	6,133,313	1,148,835	18.7		909,409	14.8		239,426	3.9	
1995	5,497,824	1,113,693	20.3		616,784	11.2		496,909	9.0	
1996	2,560,192	265,961	10.4		270,617	10.6		(4,655)	-0.2	
1997	8,905,235	1,174,025	13.2	17.6	597,293	6.7	11.3	576,731	6.5	6.3
1998	21,756,216		0.0	8.3	4,596	0.0	5.3	(4,596)	0.0	2.9
1999	9,569,466		0.0	5.3	13,462	0.1	3.1	(13,462)	-0.1	2.2
2000	10,611,085	2,917,118	27.5	8.2	851,477	8.0	3.3	2,065,640	19.5	4.9
2001	10,079,147	1,973,691	19.6	10.0	1,993,829	19.8	5.7	(20,138)	-0.2	4.3
2002	13,144,993	1,533,592	11.7	9.9	2,379,742	18.1	8.0	(846,150)	-6.4	1.8
2003	12,088,891	1,208,607	10.0	13.8	2,121,011	17.5	13.3	(912,404)	-7.5	0.5
2004	15,315,290	1,306,856	8.5	14.6	1,971,252	12.9	15.2	(664,396)	-4.3	-0.6
2005	7,426,563	1,536,983	20.7	13.0	3,342,225	45.0	20.3	(1,805,242)	-24.3	-7.3
2006	8,664,638	4,972,381	57.4	18.6	2,695,724	31.1	22.1	2,276,657	26.3	-3.4
2007	10,281,509	3,672,708	35.7	23.6	3,782,266	36.8	25.9	(109,557)	-1.1	-2.3
2008	9,083,916	3,764,197	41.4	30.0	4,689,426	51.6	32.5	(925,229)	-10.2	-2.4
2009	11,733,105	2,169,201	18.5	34.2	3,391,321	28.9	37.9	(1,222,120)	-10.4	-3.8
2010	7,660,141	12,570,515	164.1	57.2	4,986,596	65.1	41.2	7,583,919	99.0	16.0
2011	9,210,495	1,131,945	12.3	48.6	2,767,426	30.0	40.9	(1,635,481)	-17.8	7.7
2012	9,583,537	1,495,667	15.6	44.7	3,097,894	32.3	40.1	(1,602,227)	-16.7	4.7
2013	6,521,014	296,727	4.6	39.5	2,926,160	44.9	38.4	(2,629,433)	-40.3	1.1
2014	8,392,283	1,491,999	17.8	41.1	4,304,042	51.3	43.7	(2,812,043)	-33.5	-2.6
2015	9,727,135	1,295,380	13.3	13.2	4,942,304	50.8	41.5	(3,646,925)	-37.5	-28.4
2016	9,013,566	1,868,875	20.7	14.9	3,698,656	41.0	43.9	(1,829,781)	-20.3	-29.0
2017	8,170,347	842,738	10.3	13.9	4,101,514	50.2	47.8	(3,258,776)	-39.9	-33.9
2018	9,133,092	(133,705)	-1.5	12.1	4,047,542	44.3	47.5	(4,181,247)	-45.8	-35.4
Total	252,609,530	52,142,422	20.6		66,112,812	26.2		(13,970,390)	-5.5	

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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1993	12,345,547	2,524,434	20.4		1,610,244	13.0		914,190	7.4	
1994	6,132,492	1,148,835	18.7		909,409	14.8		239,426	3.9	
1995	5,497,343	1,113,693	20.3		616,784	11.2		496,909	9.0	
1996	2,559,267	265,961	10.4		270,617	10.6		(4,655)	-0.2	
1997	8,902,760	1,174,025	13.2	17.6	597,293	6.7	11.3	576,731	6.5	6.3
1998	21,754,729		0.0	8.3	4,596	0.0	5.3	(4,596)	0.0	2.9
1999	9,560,988		0.0	5.3	13,462	0.1	3.1	(13,462)	-0.1	2.2
2000	10,610,781	2,917,118	27.5	8.2	851,477	8.0	3.3	2,065,640	19.5	4.9
2001	10,078,436	1,973,691	19.6	10.0	1,993,829	19.8	5.7	(20,138)	-0.2	4.3
2002	13,144,764	1,533,592	11.7	9.9	2,379,742	18.1	8.0	(846,150)	-6.4	1.8
2003	12,111,789	1,208,607	10.0	13.8	2,121,011	17.5	13.3	(912,404)	-7.5	0.5
2004	15,353,546	1,306,856	8.5	14.6	1,971,252	12.8	15.2	(664,396)	-4.3	-0.6
2005	7,750,593	1,536,983	19.8	12.9	3,342,225	43.1	20.2	(1,805,242)	-23.3	-7.3
2006	8,299,685	4,972,381	59.9	18.6	2,695,724	32.5	22.1	2,276,657	27.4	-3.4
2007	10,281,509	3,672,708	35.7	23.6	3,782,266	36.8	25.9	(109,557)	-1.1	-2.3
2008	9,083,916	3,764,197	41.4	30.0	4,689,426	51.6	32.5	(925,229)	-10.2	-2.4
2009	11,733,105	2,169,201	18.5	34.2	3,391,321	28.9	38.0	(1,222,120)	-10.4	-3.8
2010	7,660,141	12,570,515	164.1	57.7	4,986,596	65.1	41.5	7,583,919	99.0	16.2
2011	9,210,495	1,131,945	12.3	48.6	2,767,426	30.0	40.9	(1,635,481)	-17.8	7.7
2012	9,583,537	1,495,667	15.6	44.7	3,097,894	32.3	40.1	(1,602,227)	-16.7	4.7
2013	6,521,014	296,727	4.6	39.5	2,926,160	44.9	38.4	(2,629,433)	-40.3	1.1
2014	8,392,283	1,491,999	17.8	41.1	4,304,042	51.3	43.7	(2,812,043)	-33.5	-2.6
2015	9,727,135	1,295,380	13.3	13.2	4,942,304	50.8	41.5	(3,646,925)	-37.5	-28.4
2016	9,013,566	1,868,875	20.7	14.9	3,698,656	41.0	43.9	(1,829,781)	-20.3	-29.0
2017	8,170,347	842,738	10.3	13.9	4,101,514	50.2	47.8	(3,258,776)	-39.9	-33.9
2018	9,133,092	(133,705)	-1.5	12.1	4,047,542	44.3	47.5	(4,181,247)	-45.8	-35.4
Total	252,612,861	52,142,422	20.6		66,112,812	26.2		(13,970,390)	-5.5	

ARIZONA PUBLIC SERVICE COMPANY
PALO VERDE DECOMMISSIONING TRUST
PROPOSED NUCLEAR DECOMMISSIONING TRUST FUNDING SCHEDULES
(Dollars in Thousands)

	Currently Expected Unit Closure Date				
	6/1/2045	4/24/2046	11/25/2047		
YEAR	UNIT 1	UNIT 2	UNIT 3	TOTAL[1]	ACC JURISDICTIONAL AMOUNT[2]
2022	$377	$868	$1,036	$2,281	$2,276
2023	$377	$868	$1,036	$2,281	$2,276
2024	-	$2,281	-	$2,281	$2,276
2025	-	$2,281	-	$2,281	$2,276
2026	-	$2,281	-	$2,281	$2,276
2027	-	$2,281	-	$2,281	$2,276
2028	-	$2,281	-	$2,281	$2,276
2029	-	$2,281	-	$2,281	$2,276
2030	-	$2,281	-	$2,281	$2,276
2031	-	$2,281	-	$2,281	$2,276
2032	-	$2,281	-	$2,281	$2,276
2033	-	$2,281	-	$2,281	$2,276
2034	-	$2,281	-	$2,281	$2,276
2035	-	$2,281	-	$2,281	$2,276
2036	-	$2,281	-	$2,281	$2,276
2037	-	$2,281	-	$2,281	$2,276
2038	-	$2,281	-	$2,281	$2,276
2039	-	$2,281	-	$2,281	$2,276
2040	-	$2,281	-	$2,281	$2,276
2041	-	$2,281	-	$2,281	$2,276
2042	-	$2,281	-	$2,281	$2,276
2043	-	$2,281	-	$2,281	$2,276
2044	-	$2,281	-	$2,281	$2,276
2045	-	$2,281	-	$2,281	$2,276
2046	-	$570	-	$570	$569
2047	-	-	-	-	-
	$ 754	$ 52,488	$ 2,072	$ 55,314	$ 55,193

1. Arizona Public Service Company (APS) is proposing to keep the level of Decommissioning Trust funding constant. Therefore, APS is not proposing any additional funding even though APS anticipates higher amounts than what are reflected in this Schedule. See EAB_WP78DR for the full Decommissioning Trust funding amount.
2. ACC Jurisdictional share is approximately 99.80%.

DIRECT TESTIMONY OF ROGER A. MORIN
On Behalf of Arizona Public Service Company
Docket No. E- 01345A-22-0144

October 2022

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Proxy Group for Arizona Public Service ..... Attachment RAM-02DR

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Allowed Risk Premium Analysis..... Attachment RAM-09DR

CAPM, Empirical CAPM ..... Attachment RAM-10DR

Flotation Cost Allowance ..... Attachment RAM-11DR

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-22-0144)

I. INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government. I am testifying on behalf of Arizona Public Service Company (APS or the Company). APS is a wholly-owned subsidiary of Pinnacle West Capital Corporation (Pinnacle West or PNW).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, University of Montreal, McGill University, and

Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of S&P Global Intelligence (formerly SNL Knowledge Center or SNL), for whom I have conducted frequent national executive-level education seminars throughout the United States. In the last 40 years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and "Utility Capital Allocation," which I have developed on behalf of S&P Global Intelligence.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on regulatory finance, *Utilities' Cost of Capital*, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, *Regulatory Finance*, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, *The New Regulatory Finance*, was published in 2006, and my latest book *Modern Regulatory Finance* was recently published in January 2022. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management, corporate litigation, and regulatory policy.

Please see attachment RAM-01DR for my professional qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America, including the Arizona Corporation Commission ("the Commission") and the Federal Energy Regulatory Commission among several others. I have testified before the following state, provincial, and other local regulatory commissions:

Alabama	Florida	Missouri	Oklahoma
Alaska	Georgia	Montana	Ontario
Alberta	Hawaii	Nebraska	Oregon
Arizona	Illinois	Nevada	Pennsylvania
Arkansas	Indiana	New Brunswick	Quebec
British Columbia	Iowa	New Hampshire	South Dakota
California	Arizona	New Jersey	Tennessee
City of New Orleans	Louisiana	New Mexico	Texas
Colorado	Maine	New York	Utah
CRTC	Manitoba	Newfoundland	Vermont
Delaware	Maryland	North Carolina	Virginia
District of Columbia	Michigan	North Dakota	Washington
FCC	Minnesota	Nova Scotia	West Virginia
FERC	Mississippi	Ohio	

The details of my participation in regulatory proceedings are also provided in attachment RAM-01DR.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the common equity ("ROE") invested in APS's

electric utility operations in the State of Arizona. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would:

(1) be fair to ratepayers;

(2) allow APS to attract the capital needed for infrastructure and reliability investments on reasonable terms;

(3) maintain APS's financial integrity; and

(4) be comparable to returns offered on comparable risk investments.

Q. PLEASE BRIEFLY IDENTIFY THE ATTACHMENTS ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony attachments RAM-01DR through RAM-11DR. These attachments relate directly to points in my testimony and are described in further detail in connection with the discussion of those points in my testimony.

Q. DR. MORIN, PLEASE DESCRIBE THE CURRENT RISK ENVIRONMENT IN WHICH ELECTRIC UTILITY COMPANIES, INCLUDING APS, OPERATE.

A. The graph below[1] illustrates schematically the paradigm shift in the electric utility industry's risk profile. The upper half displays the traditional business model and the lower half displays the new business environment. In a nutshell, the industry is experiencing declining demand growth, rising operating costs, rising capital costs, while at the same time the industry is beset by lower allowed returns. It is not surprising that investor risk perceptions have escalated in such an a "perfect storm" environment.

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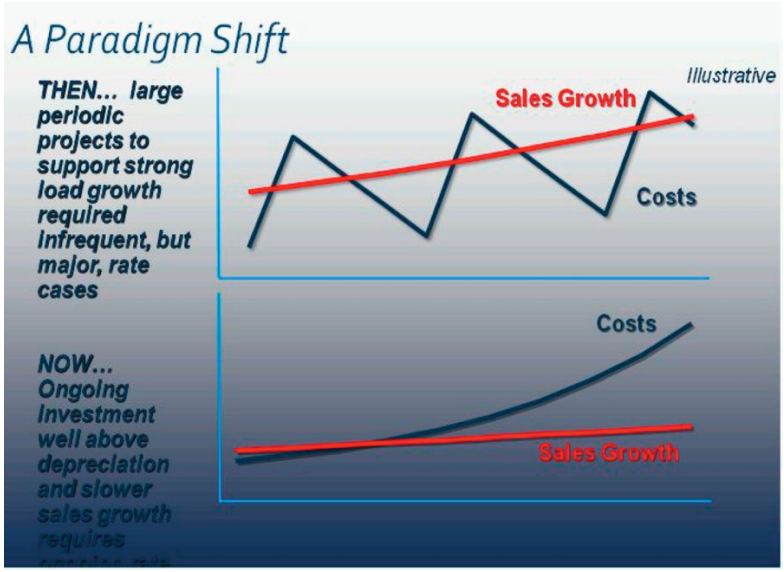
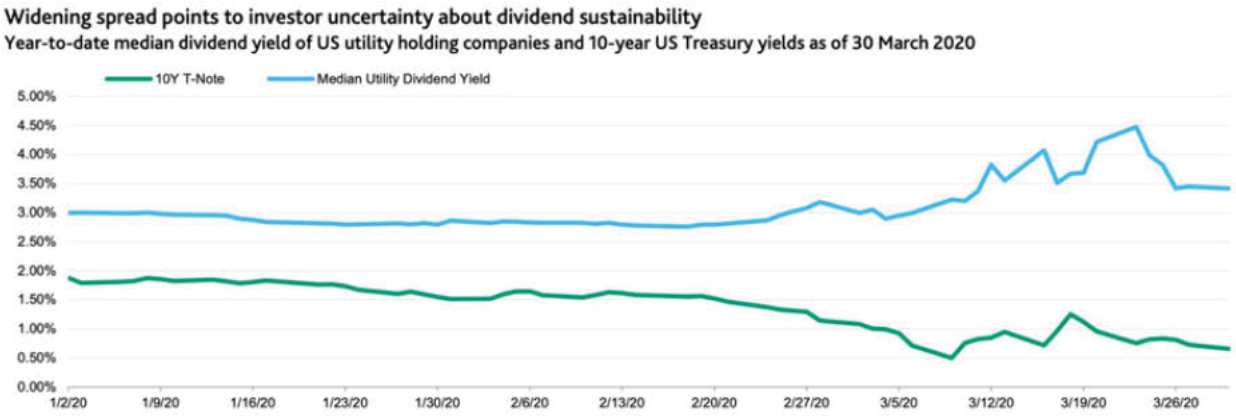
[1] Dr. R. A. Morin S&P Global Intelligence Seminar "*Essentials of Regulatory Finance*", 2019

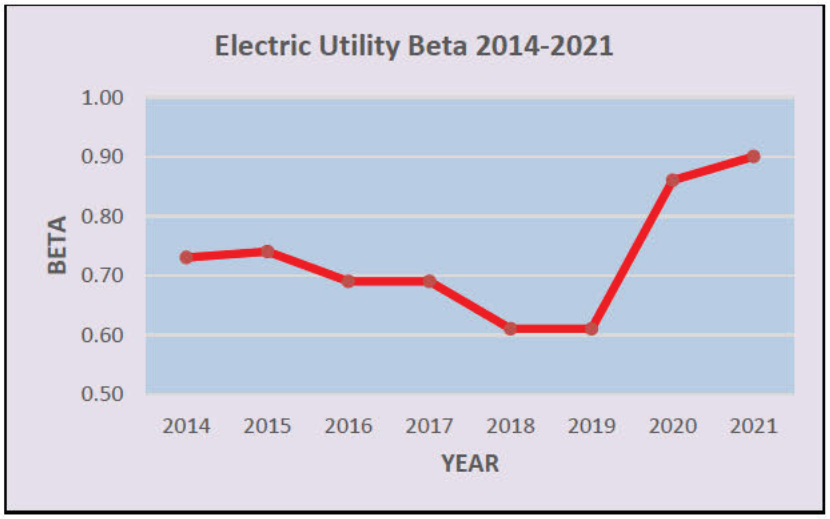


Q. HAVE THE RISK PERCEPTIONS OF THE ELECTRIC UTILITY INDUSTRY INCREASED IN RECENT YEARS?

A. Yes, they have intensified dramatically, and that is the reason why cost of equity estimates for the industry are escalating. The two graphs below illustrate my point. The first graph shows the widening spread between the dividend yields of electric utility stocks and the yield on long-term Treasury bonds in 2021, indicating higher risk perceptions. The second graph shows a dramatic increase in the average beta risk measure for electric utility stocks over the 2014-2021 period, rising from the 0.65 level to the unprecedented level of close to 1.0. The beta risk measure for APS's parent company PNW is close to 1.0 at 0.90. A beta figure approaching 1.0 is an indication that electric utility stocks are becoming as risky as the average stock.



Note: Median utility dividend yield based on the 38 electric and gas utility parent companies identified in this report
Source: FactSet



Q. TO WHAT DO YOU ATTRIBUTE THIS QUANTUM INCREASE IN THE RISK PROFILE OF THE ELECTRIC UTILITY INDUSTRY?

A. Four major challenges today are facing electric utilities like APS and have resulted in a "Perfect Storm," and hence higher risks.

First, U.S. economic growth has outpaced energy consumption growth over the past decade. Due to improvements in energy science and productivity, growth in energy consumption has slowed. Society as a whole is doing more with less energy. Clearly, the century-old model of an industry founded on the thesis of uninterrupted rising energy usage is becoming somewhat archaic.

Second, and this is certainly the case for APS, at the same time that energy consumption growth is receding, record amounts of new capital are required for replacing aging infrastructure, improving reliability, and delivering renewable generation. The utility industry's cost of replacing generation assets, transformers, and power lines is estimated to be in excess of $4.8 trillion over the next decades.[2]

The shift in generation mix to renewable sources of energy, possibly hydrogen as a fuel source, and away from fossil fuels is accelerating. As a result, utility companies look to upgrade and modernize the country's aging energy infrastructure and accommodate the expansion of electric vehicles, energy efficiency, battery storage and smart grid technologies that facilitate the transition toward decarbonization.

There is also an urgent need for capital investments in new transmission infrastructure in order to interconnect the new renewable energy resources to the grid and to strengthen the grid in light of unprecedented and unpredictable extreme weather events which have challenged the grid's reliability and resiliency,

Third, utility companies are facing higher business risks. Electric utilities are witnessing the emergence of 'prosumers,' that is, customers (residential, commercial, industrial) who are both consumers and producers. This paradigm shift from a consumer-centric model to a prosumer-centric model adds to the industry's business risk because prosumers who generate their own energy and feed it back to the grid not only create bypass

[2] Clean Capital, D. Daly, Director of Investments & Capital Markets, "Four challenges that will shape electric utilities this decade," Feb. 6, 2019.

risks but also operational complexity at the grid level because of added difficulties for utility companies to forecast supply and demand. To illustrate, companies such as Google, Amazon, Apple and Walmart will increase utility companies' business risks and forecasting risks by setting up their own distributed solar and wind farms.

Adding to bypass risks, distributed energy resources are experiencing exponential growth which is expected to double by 2023[3]. The declining costs of distributed solar, energy storage, smart thermostats, electric vehicles, and small-scale combined heat and power will continue to propel this growth. To quote the trade journal Transmission & Distribution World: "*The century-old, one-way electricity delivery model that has been serving the utility industry traditionally, is proving to be inadequate to support the rising demand and diverse energy options being explored by today's consumers.*"

Fourth, operating costs (labor, materials, commodities, etc.) are trending upward due to rising inflation and supply chain bottlenecks. For example, transformers are currently experiencing an acute shortage.

Q. WHAT DO YOU CONCLUDE FROM THIS PARADIGM SHIFT IN THE INDUSTRY'S RISK PROFILE.

A. Given the new paradigm shift in the industry, it is obvious that state regulatory support, including a fair opportunity to earn adequate returns on equity, will be instrumental to ensure ongoing capital attraction in the utility sector at reasonable costs.

[3] Clean Capital, op. cit.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING APS' COST OF COMMON EQUITY.

A. It is my opinion that a fair, reasonable and sufficient ROE for APS is 10.25%. My recommended return is predicated on the Commission's adoption of the Company's proposed capital structure which consists of 52% common equity capital. A minimum ROE of 10.25% is required in order for the Company to: (i) attract capital on reasonable terms, (ii) maintain its financial integrity, and (iii) earn a return commensurate with returns on comparable risk investments.

My ROE recommendation is derived from cost of capital studies that I performed using the financial models available to me and from the application of my professional judgment to the results. I applied various cost of capital methodologies, including the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Risk Premium Models to a group of investment-grade, dividend-paying, vertically-integrated electric utilities. The companies were required to have the majority of their revenues from regulated utility operations and have significant clean energy transformation profiles. I have also surveyed and analyzed the historical risk premiums in the utility industry and risk premiums allowed by regulators as indicators of the appropriate risk premium for the electric utility industry.

My recommended ROE reflects the application of my professional judgment to the results in light of the indicated returns from my DCF, CAPM, and Risk Premium analyses. I do consider my recommended ROE as conservative given the higher relative risks of the Company by virtue of its high regulatory risks relative to its peers, significant external

financing requirements from its large construction program, a rising interest rate environment, and a generally heightened industry risk environment.

Q. WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE COMMISSION TO APPROVE A ROE OF 10.25% FOR APS'S ELECTRIC UTILITY OPERATIONS?

A. Yes. My analysis shows that a 10.25% ROE fairly compensates investors, maintains APS's credit strength, and will permit the attraction of capital needed for utility infrastructure and reliability capital investments required in the service territory served by APS.

Q. **PLEASE EXPLAIN HOW LOW ALLOWED ROES CAN INCREASE THE FUTURE COST OF CAPITAL AND RATEPAYER COSTS.**

A. If a utility is authorized a ROE below the level required by equity investors, the utility or its parent will find it difficult to access equity capital. Investors will not provide equity capital at the current market price if the earnable ROE is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return that equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new

issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

However, as a company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on a company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility for both debt and equity financing and increases the possibility a company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that APS has access to capital markets on reasonable terms for its capital needs, a fair and reasonable authorized ROE of 10.25% is required.

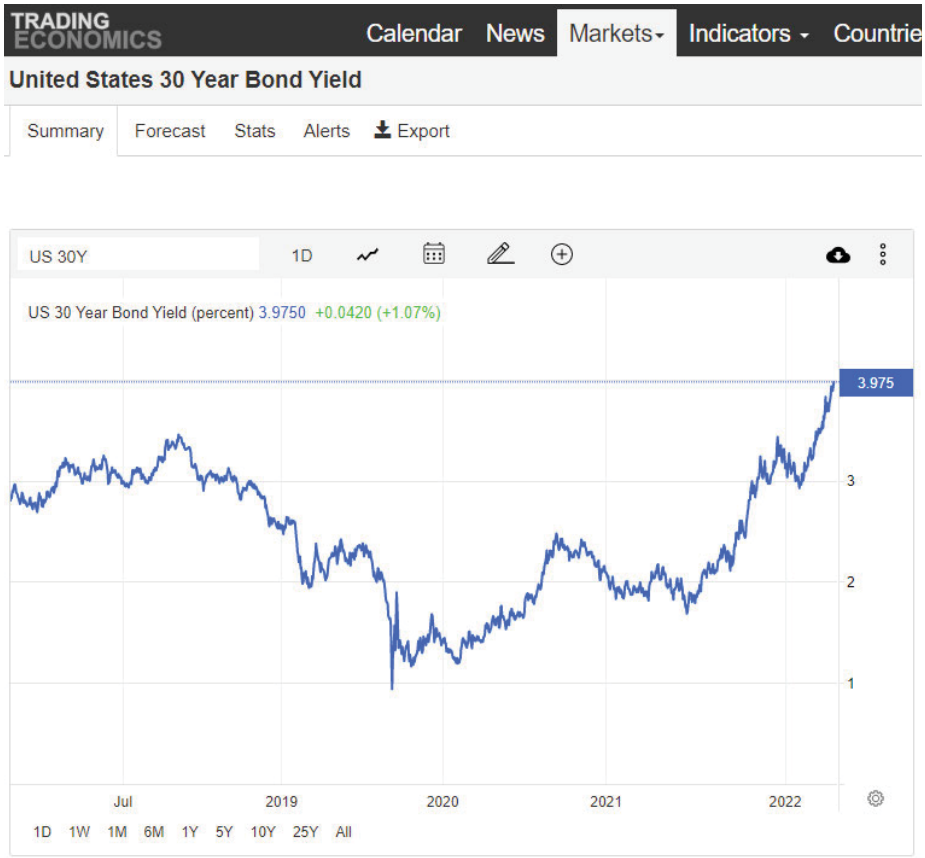
APS must secure outside funds from capital markets to finance required utility plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Thus, rate relief and supportive regulation, including approval of my recommended ROE, are essential requirements.

Q. ARE CAPITAL MARKET CONDITIONS IMPORTANT IN DETERMING THE COST OF CAPITAL FOR A PUBLIC UTILITY?

A. Yes, they are. The cost of capital is determined in part by the level and trend of interest rates, by the level of inflation, and by current and prospective economic conditions.

Q. WHAT HAS BEEN THE RECENT TREND IN INTEREST RATES AND ITS IMPACT ON THE COST OF CAPITAL?

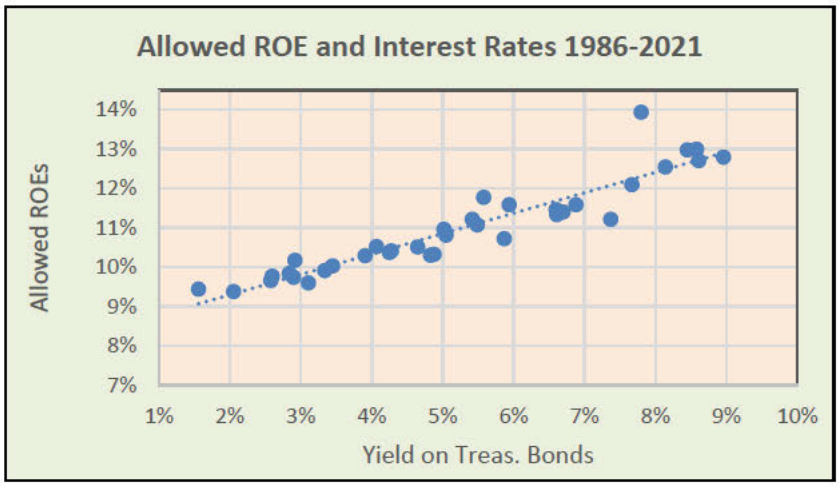
A. The steady decline in interest rates over the last decade has ended. As the graph below demonstrates so far in 2022, the 30-year Treasury bond yield has risen to the 3% level, and is expected to rise further in response to record-high inflation, a more robust economic growth, supply shortages, labor shortages, and the Federal Reserve's restrictive monetary policy.



Q. HOW DO INTEREST RATES IMPACT A UTILITY COMPANY'S COST OF EQUITY CAPITAL AND ALLOWED RETURN ON EQUITY?

A. The higher the level of interest rates, the higher is the cost of equity capital and the allowed

ROE. The converse is also true. This is clearly seen in the graph below which shows the positive relationship between allowed ROEs and the yield on long-term Treasury bonds over the 1986-2021 period.



Allowed returns have typically tracked the level of interest rates as the graph demonstrates. Hence, it is no surprise that ROE estimates, including my own, have risen in response to both higher interest rates and a higher risk profile for electric utilities. With regards to the latter, as I discussed earlier in my testimony, a "Perfect Storm" is impacting electric utilities: declining sales per customer, coupled with rising costs, at a time when huge capital investments are required due to aging infrastructure and, in the case of APS, population migration to the service territory and continuing economic development. It is no surprise that investor risk perceptions and return requirements have increased in response to not only higher interest rates but also to this paradigm shift in the electric utility industry's risk profile.

Q. PLEASE DESCRIBE HOW THE REMAINDER OF YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into four broad sections:

(II) Regulatory Framework and Rate of Return;

(III) Cost of Equity Estimates;

(IV) Risk Analysis

(V) Summary and Conclusions

Section II discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. Section III contains the application of DCF, Risk Premium, and CAPM tests. Section IV discusses the Company's risks relative to its peers. The results from the various approaches used in determining a fair return are summarized and the Company's higher relative risks are discussed in Section V.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company has a fair opportunity to recover its prudently incurred costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to permit a company a fair opportunity to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds (i.e., investors' required rate of return) is

more difficult to estimate. It is the purpose of the next section of my testimony to estimate a fair and reasonable ROE for APS's electric utility operations in the State of Arizona.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE ROE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); and
2. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

The *Bluefield* case set the standard against which just and reasonable rates of return are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public *equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties* ... The *return should be reasonable*, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to *maintain and support its credit* and *enable it to raise money* necessary for the proper discharge of its public duties.

Bluefield Water Works & Improvement Co., 262 U.S. at 692 (emphasis added).

The *Hope* case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the *Bluefield* case and recognized that revenues must cover "capital costs." The Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs

> of the business. These include service on the debt and dividends on the stock ... By that standard *the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks*. That return, moreover, should be sufficient to *assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital*.

Hope Natural Gas Co., 320 U.S. at 603 (emphasis added).

The United States Supreme Court reiterated the criteria set forth in *Hope* in *Federal Power Commission v. Memphis Light, Gas & Water Division*, 411 U.S. 458 (1973); in *Permian Basin Rate Cases*, 390 U.S. 747 (1968); and, most recently, in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). In the *Permian Basin Rate Cases*, the Supreme Court stressed that a regulatory agency's rate of return order should

> *reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed.*

Permian Basin Rate Cases, 390 U.S. at 792.

Therefore, the "end result" of this Commission's decision should be to allow APS the opportunity to earn a ROE that is:

(i) commensurate with returns on investments in other firms having corresponding risks;

(ii) sufficient to assure confidence in APS's financial integrity; and

(iii) sufficient to maintain APS's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (e.g., bonds and common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by

multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

Although utilities like APS enjoy varying degrees of market dominance in the sale of public utility services, they (or their parent companies) must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital, including the capital investments required to support the utility infrastructure. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require (e.g., the interest on debt capital or the expected ROE relative to the utility's credit quality). In order to attract the necessary capital, utilities must compete with alternative uses of capital and offer a return commensurate with the associated risks.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is

the price of capital. If there are differences in the risk of the investments, competition among firms for the limited supply of capital will produce different prices for that capital. The capital markets translate these differences in risk into differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand, which is strongly influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF APS'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of APS's cost of equity. One relates to the supply side of capital markets, the other to the demand side.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding inappropriate returns at a given risk level in favor of those investment activities offering appropriate returns for a given level of risk. This principle implies that a company will be unable to attract capital funds unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the expected return on these investments equals, or exceeds, a company's cost of capital. This principle is the essence of the regulatory compact. In

other words, a regulatory commission should set rates at a level sufficient to create equality between the expected return on physical asset investments and a company's cost of capital. Failure of the regulator to allow prudent management a fair opportunity to attempt to earn the market required rate of return would be viewed by the capital markets as a breach of the regulatory compact. The financial markets would react to this situation by lowering the utility's common stock price and its credit rating—both of which increase capital costs and reduce access to capital.

Q. HOW DOES APS OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by APS are obtained in two general forms, debt capital and equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because there are no contractual payments as in the case of debt funds. Rather, the dividend payments received from common stock are not contractual or guaranteed in nature. While both dividend payments and interest payments are risky, dividend payments can increase, decrease or be omitted. Once a cost of common equity estimate has been developed, it can then be combined with the embedded cost of debt and the utility's capital structure, in order to arrive at the overall cost of capital (overall rate of return).

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through

their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and the ability to attract capital on reasonable terms. The "attraction of capital" standard focuses on investors' return requirements that are generally determined using market value methods, such as the DCF, CAPM, or Risk Premium methods. These market value tests define "fair return" as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

III. COST OF EQUITY CAPITAL ESTIMATES

Q. HOW DID YOU ESTIMATE A FAIR ROE FOR APS?

A. I employed three methodologies: (1) the DCF methodology, (2) the CAPM, and (3) the Risk Premium. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to APS. I then

applied the aforementioned methodologies to a reference group of vertically-integrated electric utilities.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending corporate transformations such as acquisitions, a new corporate identity due to restructuring activities, and weather anomalies (storms, hurricanes, droughts, wildfires, etc). The added advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

As I have stated, there are three broad generic market-based methods available to measure the cost of equity: DCF, CAPM, and Risk Premium. All three of these methods are accepted and used by the financial community and firmly supported in the financial

literature. The weight accorded to any one method may vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of professional judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the theory and apply the method. Each method has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the cost of equity.

In short, it is inappropriate to utilize a single measure of the cost of equity, such as DCF or CAPM, in order to determine the cost of capital of a public utility or to quantify the impact of a particular factor on the cost of capital.

Q. ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN ENVIRONMENTS CHARACTERIZED BY VOLATILITY IN CAPITAL MARKETS AND ECONOMIC UNCERTAINTY?

A. Yes, there are. The traditional cost of equity estimation methodologies are difficult to implement when you are dealing with instability and volatility in the capital markets and the uncertain economy both in the U.S. and abroad. This is not only because stock prices are volatile at this time, but also because the electric utility industry is experiencing substantial change, for example, changing customer expectations, improving energy

efficiency technologies, declining per customer usage, the implementation of new grid technologies, the advent of game-changing distributed generation technologies, the transition to stringent carbon-free or renewable energy standards and the need to secure vast amounts of external capital over the next decade, regardless of capital market conditions. Past earnings and dividend trends may simply not be indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including declining per customer usage, restructuring activity in the industry, and falling margins per units sold. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be necessarily representative of future trends for several specific electric utilities involved in mergers, acquisitions, and corporate tranformations as these companies going forward are not the same companies for which historical data are available.

In short, given the volatility in capital markets and economic uncertainties, the utilization of multiple methodologies is critical. The reliance on a single methodology tends to complicate the estimation process, as does the reliance on a small group of peer companies as I discuss below.

A. DCF Estimates

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a mature company is to examine

the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_0 + g$$

where: K_e = investors' expected return on equity
D_1 = expected dividend at the end of the coming year
P_0 = current stock price
g = expected growth rate of dividends, earnings, stock price, and book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return (K_e) can be viewed as the sum of an expected dividend yield (D_1/P_0) plus the expected growth rate of future dividends and stock price (g). The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer K_e from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 9 of my latest 2022 reference text, *Modern Regulatory Finance*. The standard DCF model requires the following main assumptions:

(i) a constant average growth trend for dividends and earnings;
(ii) a stable dividend payout policy;
(iii) a discount rate in excess of the expected growth rate; and
(iv) a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends.

The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE APS'S COST OF EQUITY WITH THE DCF MODEL?

A. In estimating APS's cost of equity, I applied the DCF model to a group of investment-grade, dividend-paying, electric utilities that are covered in the Value Line database. The group is described in further detail below.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0), and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

Q. HOW DID YOU ESTIMATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the then-current price of the security at the time of estimating the cost of equity. This is because current stock prices incorporate all publicly available information regarding financial market expectations for that stock which provides the best indication of the true stock prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a DCF estimate should start with current prices.

In implementing the DCF model, I have used the dividend yields reported in the Value Line Investment Analyzer ("VLIS") software. Basing dividend yields on average

results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield.

Q. WHY DID YOU MULTIPLY THE SPOT DIVIDEND YIELD BY (1 + g) RATHER THAN BY (1 + 0.5g)?

A. Some analysts multiply the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g). This procedure understates the return expected by the investor.

The fundamental assumption of the basic annual DCF model is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model, in conjunction with the current market price, is the full prospective dividend to be received over the next year. Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, multiplying the spot dividend yield by (1 + 0.5g) understates the proper dividend yield.

Moreover, multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments typically employed by publicly-traded electric utility holding companies. Use of this method is conservative in the sense that the annual DCF model fully ignores the more frequent compounding of quarterly dividends.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined the consensus growth estimates developed by professional analysts. These forecasts are made by large reputable organizations, and the data are readily available, are representative of the consensus view of investors and are thus consistent with the use of current market prices. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research (Zacks), Reuters, and Yahoo Finance. As proxies for investors' growth expectations in applying the DCF model I used both analysts' long-term growth forecasts reported in Zacks and Value Line's growth forecasts.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO UTILITIES?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore

redundant. Second, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. This considerable literature is summarized in Chapter 12 of my most recent textbook, *Modern Regulatory Finance*.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH TO APPLY THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by a company, 'b', by the expected return on book equity, ROE, as follows:

where: g = expected growth rate in earnings/dividends
b = expected retention ratio
ROE = expected return on book equity

Q. DO YOU HAVE ANY RESERVATIONS IN REGARDS TO THE SUSTAINABLE GROWTH METHOD?

A. Yes, I do. First, the sustainable method of predicting growth contains a circular logic trap: the method requires an estimate of expected return on book equity to be implemented. But if the expected return on book equity input required by the model differs from the recommended ROE, a fundamental contradiction in logic follows. Second, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

Q. DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF MODEL?

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover, it is reasonable to expect some utilities to lower their dividend payout ratios over the next several years in response to heightened business risk and the need to fund very significant construction programs and infrastructure upgrades over the next decade. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks and finance large infrastructure investments. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Yahoo Finance, Zacks Investment, First Call Thompson, Reuters, and IBES provide comprehensive compilations of investors' earnings forecasts. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal

investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

Q. HOW DID YOU APPROACH THE COMPOSITION OF COMPARABLE GROUPS IN ORDER TO ESTIMATE APS'S COST OF EQUITY WITH THE DCF METHOD?

A. Because APS is not publicly traded, the DCF model cannot be applied directly to APS and proxies must be used. In the uncertain capital market and industry environment, it is important to select relatively large sample sizes representative of the utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the equity market as a whole and utility industry capital market data are volatile. As a result of this volatility, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth, are mitigated. Utilizing a large portfolio of companies reduces the influence of either overestimating or underestimating the cost of equity for any one individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend

to cancel out owing to the law of large numbers, provided that the errors are independent.[4] The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

Moreover, small samples are subject to measurement error, and in violation of the Central Limit Theorem of statistics.[5] From a statistical standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data, such as those listed above.

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4 If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

5 The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. Even if the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A far safer procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that a company's risk profile differs from that of the industry average.

Q. PLEASE DESCRIBE THE PROXY GROUP FOR APS'S UTILITY BUSINESS?

A. As proxies for APS, I examined a group of investment-grade, dividend-paying, electric utilities covered in Value Line's Electric Utility industry group, meaning that these companies all possess utility assets similar to APS's. I began with all the companies designated as electric utilities that are covered in the Value Line Investment Survey ("Value Line") as shown on attachment RAM-02DR. Pacific Gas & Electric was eliminated because of suspended dividends. AvantGrid and PNM Resources were eliminated on account of the ongoing merger re-negotiations. Companies who are primarily distribution-only electric utilities were eliminated so as to focus primarily on vertically-integrated electric utilities like APS. Private partnerships, private companies, and companies below investment-grade (with a Moody's bond rating below Baa3) were eliminated. Until was eliminated on account of its very small size and in order to minimize

any stock price anomalies due to thin trading.[6] Only those electric utilities with at least 80% of their assets regulated were retained[7].

The final group of twenty-four companies that comprise the proxy group is shown on attachment RAM-02DR. I stress that this proxy group must be viewed as a portfolio reflecting the risk of the vertically-integrated electric utility industry as a whole. It would be inappropriate to select any particular company or subset of companies from this group and infer the cost of common equity from that company or subset alone without rigorously determining to what degree the subject company is similar in risk to that company or subset.

CHAIRWOMAN MARQUEZ PETERSON'S LETTER

Q. ARE YOU AWARE OF CHAIRWOMAN MARQUEZ PETERSON'S ("CHAIRWOMAN") JUNE 2, 2022 LETTER THAT WAS FILED IN THE ARIZONA PUBLIC SERVICE COMPANY ("APS") DOCKET (DOCKET NO. E-01345A-22-0144).

A. Yes, I am. The Chairwoman's letter requested information on the impact of the Company's voluntary clean energy commitments on its cost of capital. In particular, the Chairwoman requested the development of a "Clean Energy" proxy group in order to address such impact.

[6]This is necessary in order to minimize the well-known thin trading bias in measuring beta. Unitil was excluded for this reason.

[7] Edison Electric Institute's master database of electric utilities includes a list of "Regulated Utilities" as opposed to its list of "Mostly Regulated" utilities. Only companies in the former list are included in the peer group.

Q. DOES THE PEER GROUP MEET THE CHAIR'S REQUEST?

A. Yes, it does. According to each of the 24 companies' 2021 annual report and/or Form 10-Ks, multiple references and discussions are made to Clean Energy commitments, renewable energy projects, renewable portfolio standards (RPS) compliance targets, related capital investments, multiple Integrated Resource Planning (RSP) references, and state-mandated targets. Besides, as discussed more fully below, such risks are already reflected in various measures of risk employed by investors.

Q. ARE THERE ANY RISKS INHERENT IN CLEAN ENERGY COMMITMENTS AND RENEWABLE ENERGY PROJECTS?

A. Yes, there are. Three major risk components characterize decarbonizing energy systems: technology risk, development risk and pricing risk. Technology can fail. Development risks come in three principal forms: siting, permitting, and transmission access. The sale price of electricity might be unknown and demand more difficult to forecast.

Q. ARE THESE RISKS ACCOUNTED FOR IN YOUR COST OF CAPITAL ESTIMATES?

A. Yes, they are. Allowed ROEs should not be adjusted downward or upward in order to account for the risk impact of clean-energy mandates on a company's business risks because market-derived returns are estimated from market information on the cost of common equity for other comparable utilities which already incorporates the impacts of these risks. To do so would constitute double-counting.

Q. THE CHAIR'S LETTER REQUESTS APS TO ADDRESS THE RISKS OF APS'S CLEAN ENERGY COMMITMENT AND APS'S ABILITY TO MEET THOSE COMMITMENTS. HOW MIGHT YOU CONCEPTUALIZE THESE RISKS?

A. Regulated public utilities are entitled to a fair opportunity to recover through the rates they are permitted to charge all prudent costs of providing service, including a fair return on the capital invested to serve the public. The landmark *Bluefield* and *Hope* cases established that a fair return is one commensurate with those available on alternative investments of comparable risk.

The cost of capital, that is, investor's required rate of return, can be conceptualized as the sum of the risk-free rate of interest and a risk premium expressed as follows:

$$K = R_f + RP$$

Where: K = investor required return;

R_f = the risk-free rate; and

RP = various required risk premiums

The risk-free rate is the return required for postponing consumption while the risk premium is the additional return required by the investor for assuming the risk of the particular investment. The risk premium component can be further disaggregated into three components as follows:

Risk Premium = Business risk + Regulatory risk + Financial risk

Business risk encompasses all the operating factors that collectively increase the probability that expected future cash flows accruing to investors may not be realized. Such factors include the impact of economic cycles on the company's service territory, weather patterns, the availability of substitutes for the company's product, income and price

elasticity of demand, technological obsolescence, size of the necessary construction budgets, conditions in the market for the factors of production (labor and raw materials), and finally, among other business risks, would be the risk inherent in the clean energy commitment.

Regulatory risk includes the extent to which the regulatory and legislative environment leads to fair and reasonable rate awards. Regulators should consider such risks in their assessment of investment risk as investors certainly consider regulatory risks when making investment decisions as evidenced by the number of services that evaluate such risks (e.g., Value Line, Regulatory Research Associates, the major credit rating agencies and numerous equity analysts that follow common stocks).

Financial risk comes from the methods used by the company to finance its investment in plant and equipment. The use of fixed-cost financing creates additional risk due to the fixed contractual obligations associated with such capital. Debt and preferred stock carry fixed charge burdens that must be supported by earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges to the total income of the company, the greater the financial risk. One of the most important concepts in finance is that financial risk increases with the amount of fixed-cost financing employed and the greater the level of fixed-cost financing, the greater the cost of equity as well.

The risks of APS's clean energy commitment and the company's ability to meet those commitments fall in the three categories of: 1) business risk (the ability of APS to identify, obtain, install, integrate and operate clean energy technologies), 2) regulatory risk (the extent that clean energy expenditures are deemed prudent, and the company is granted

a fair opportunity by its regulators to attempt to recover those costs), and 3) financial risk (can the company finance these expenditures without causing material increases in its cost of capital and the cost of service to its customers).

Q. IS IT STATISTICALLY FEASIBLE TO RELIABLY QUANTIFY THE IMPACTS THAT A CLEAN ENERGY COMMITMENT MIGHT HAVE ON THE COST OF CAPITAL OF A PUBLIC UTILITY?

A. Even if the risk impact of clean energy commitments on the cost of capital was not already reflected in the peer companies' market data, the direct answer to that question is in the negative. There have been several comprehensive empirical studies that have investigated the impact of a particular risk characteristic on risk and the cost of capital. These studies have found that attempting to isolate the effects of individual risk characteristics on risk and the cost of capital, if any, is statistically undetectable. One explanation for this is that investors generally do not associate specific increments to their return requirements with specific micro risk factors such as CWIP inclusion for example. Investors rather tend to look at the totality of risk factors relative to those in place at comparable companies when assessing risk.

Another explanation is that the effects of one risk characteristic may be offset by another characteristic that is impacting in the reverse direction. Another explanation is that the risk characteristics that is being isolated is a diversifiable risk and investors are not compensated for risks that they should diversify away when holding a portfolio of securities – hence there is no statistically measurable impact on the cost of equity for a characteristic that the financial markets do not offer a reward for.

As I discussed earlier, to the extent that companies in the proxy group have similar risk characteristics, the use of a proxy group takes those risks into account. Where APS might differ with the focus of the Chair's inquiry would be in the particular measures of risk employed to identify the appropriate proxy group.

Q. HOW DO YOU RESPOND TO THE CHAIR'S INQUIRY WITH REGARDS TO RISK METRICS?

A. Attachment C of the Chair's inquiry asks participants in this proceeding to employ risk metrics such as voluntary clean/renewable energy standards, state mandated clean/renewable energy standards, existing generation mix, retirement of fossil capacity, and membership in regional transmission organization or independent system operator to identify appropriate companies to include in the proxy group and, presumably, identify a cost of equity increment between those companies that have a particular risk characteristic and those companies that do not. While these metrics certainly seem relevant to the question that is being asked, investors do not subscribe to such risk metrics. Investors rely on investment risk measures such as credit ratings, betas and safety ranks, notwithstanding the fact that a company's risk profile is already impounded in its stock price. These risk measures capture the relative impact of business risk, regulatory risk, and financial risk factors. Whether the focus is on clean energy commitments, automatic adjustment clauses, specific cost trackers, forward test years, etc., the impact of these is already largely embedded in investor metrics like bond ratings, betas and safety ranks.

To sum up, investors generally do not associate specific incremental return requirements with individual characteristics that are already accounted for in traditional risk metrics like bond ratings, beta risk measures, stock prices, and safety ranks. This is

because investors tend to look at the totality of risk of a company, rather than on individual granular subsets of risk.

DCF RESULTS

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR APS USING VALUE LINE GROWTH PROJECTIONS?

A. Attachment RAM-03DR Page 1 displays the DCF analysis using Value Line growth projections for the twenty-four companies in APS's proxy group. As shown on column 3, line 26 of attachment RAM-03DR Page 1, the average long-term earnings per share growth forecast obtained from Value Line is 6.50% for APS's proxy group. Combining this growth rate with the average expected dividend yield of 3.67% shown on column 4, line 26 of attachment RAM-03DR Page 1 produces an estimate of equity costs of 10.18% for APS's proxy group, as shown on column 5, line 26 of attachment RAM-03DR. Recognition of flotation costs brings the required return of equity estimate to 10.37% for the group, shown in Column 6. The need for a flotation cost allowance is discussed at length later in my testimony.

Page 2 of attachment RAM-03DR replicates the exact same analysis but without Edison International ROE estimate of 21%. The resulting DCF estimate is 9.90%

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR APS USING ANALYSTS' CONSENSUS GROWTH FORECASTS?

A. Attachment RAM-04DR displays the DCF analysis using analysts' consensus growth forecasts for the companies in APS's proxy group. Please note that the growth forecast for Otter Tail was drawn from the Yahoo Finance forecast only since the Zacks growth forecast was not available for that company.

As shown on column 3, line 26 of attachment RAM-04DR, the average long-term earnings per share growth forecast obtained from analysts is 5.47% for APS's proxy group. Combining this growth rate with the average expected dividend yield of 3.63% shown on column 4, line 26, produces an estimate of equity costs of 9.10% for APS's proxy group unadjusted for flotation cost, as shown on column 5, line 26, of attachment RAM-04DR. Recognition of flotation costs brings the required return of equity estimate to 9.29%, shown in Column 6, line 26.

Q. PLEASE SUMMARIZE THE DCF ESTIMATES FOR THE PEER GROUP.

A. Figure 1 below summarizes the DCF estimates:

Figure 1: DCF Estimates

DCF STUDY	ROE
Electric Utilities Value Line Growth	9.90%
Electric Utilities Analysts Growth	9.29%

B. CAPM Estimates

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta (β). According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta \times (R_M - R_F)$$

where: K = investors' expected return on equity
R_F = risk-free rate
R_M = return on the market as a whole
β = systematic risk (i.e., change in a security's return relative to that of the market)

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by β x (R_M - R_F). The bracketed expression (R_M - R_F) is known as the market risk premium (MRP) and sometimes known as the equity risk premium (ERP). To derive the CAPM estimate of the cost of equity, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP.

For the risk-free rate (R_F), I used 3.7%, based on yield forecasts and on the normalized yields on long-term U.S. Treasury bonds. For beta (β), I used 0.87 based on Value Line estimates. For the MRP, that is, (R_M - R_F), I used 8.0% based on historical and prospective market risk premium studies. These inputs to the CAPM are explained below.

CAPM RISK-FREE RATE

Q. HOW DID YOU ARRIVE AT YOUR RISK-FREE RATE ESTIMATE OF 3.7% IN YOUR CAPM AND RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free rate is required. I relied on two proxies. First, I examined noted economic forecasts which call for a rising trend in interest rates in response to renewed inflation fears and restrictive monetary policy. Blue Chip Economic Indicators, the Congressional Budget Office, the

U.S. Energy Information Administration, the Washington State Economic Forecast Council, Deloitte Forecast, Budget of the Federal Government, the White House Long-Term Budget Outlook, and finally Moody's forecast[8]. all project higher long-term Treasury bond rates in the future. Second, I relied on an estimate of the normalized risk-free rate, as described below.

Q. WHY DID YOU RELY ON LONG-TERM BONDS INSTEAD OF SHORT-TERM BONDS?

A. The appropriate proxy for the risk-free rate in the CAPM is the return on the longest-term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds; rather than to short-term Treasury bills or intermediate-term Treasury notes. In a CAPM or Risk Premium analysis, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, therefore, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

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[8] When only forecasts of 10-year U.S. Treasury notes are available, 50 basis points were added to obtain the 30-year forecast, based on the historical spread between 30-year and 10-year U.S. Treasury bond yields

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (*e.g.*, pension funds and insurance companies), in fact hold bonds until they mature and, therefore, are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period. Or they engage in hedging transactions in the financial futures markets. Both academicians and practitioners have extensively documented the merits and mechanics of such risk immunization strategies.

Another reason for utilizing the longest maturity Treasury bond possible is that the inflation expectations embodied in common equity market-required rates of return will, therefore, be equal to the inflation rate anticipated to prevail over the very long term. The same expectation should be embodied in the risk-free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yields the inflation expectations that influence the prices of common stocks than do short-term Treasury bills or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yields on such securities should be used as proxies for the risk-free rate in applying the CAPM. Therefore, I have relied on the forecasted yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Yes. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply. They are also used by governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury bills. This is because short-term rates, such as the yield on 90-day Treasury bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury bills may be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with investor required common stock returns.

Q. WHAT IS YOUR FIRST ESTIMATE OF THE RISK-FREE RATE ?

A. All the noted interest rate forecasts that I am aware of point to significantly higher interest rates over the next several years. Figure 2 below reports the forecast yields on 30-year US

Treasury bonds from several prominent sources cited previously.

Figure 2: Forecast Yields on 30-year U.S. Treasury Bonds

	Period	Yield
Blue Chip Economic Indicators March 2022	2024	3.9%
Budget of the U.S. Government Fiscal 2023	2032	3.8%
CBO Update July 2021	2023-2032	4.3%
Deloitte U.S. Economic Forecast Q2 2022	2024	4.9%
Wash State Econ & Revenue Forecast Council	2027	3.5%
Long-Term Budget Outlook	2020-2032	3.7%
U.S. Energy Information Admin	2023-2050	3.6%
Moody's	2024	4.4%
AVERAGE		**4.0%**

The average long-term bond yield forecast from the numerous sources is 4.0%, with little variability among the estimates, that is, the individual forecasts are quite consistent as they are closely clustered around the average. Based on this evidence, a long-term bond yield forecast of 4.0% is a reasonable estimate of the expected risk-free rate for purposes of forward-looking CAPM/ECAPM and Risk Premium analyses in the current economic environment.

Q. WHY DID YOU IGNORE THE CURRENT LEVEL OF INTEREST RATES IN DEVELOPING YOUR PROXY FOR THE RISK-FREE RATE IN A CAPM ANALYSIS?

A. I relied on projected long-term Treasury interest rates for several reasons. First, investors price securities on the basis of long-term expectations, including interest rates. Cost of capital models, including both the CAPM and DCF models, are prospective (i.e., forward-looking) in nature and must take into account current market expectations. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM

must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

Second, investors' required returns can and do shift over time with changes in capital market conditions, hence the importance of considering interest rate forecasts. Third, the fact that the numerous organizations cited on Figure 2 who provide economic forecasts devote considerable expertise and resources to developing an informed view of the future, and the fact that investors are willing to purchase such expensive services confirm the importance of economic/financial forecasts in the minds of investors. Moreover, the empirical evidence demonstrates that stock prices do indeed reflect prospective financial input data.

Fourth, given that this proceeding is to provide ROE estimates for setting electric rates going forward, forecasted interest rates are far more relevant. The use of interest rate forecasts is no different than the use of projections of other financial variables in DCF analyses.

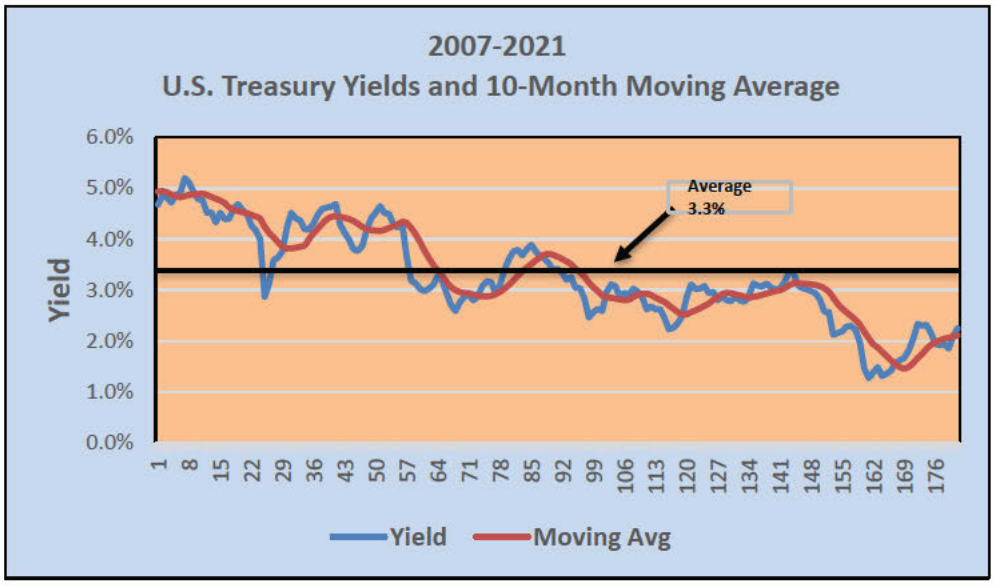
Q. DR. MORIN, WHY DID YOU ALSO RELY ON A NORMALIZED RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. I relied on a normalized risk-free rate estimate because during "crises" periods, such as the COVID-19 pandemic and the 2008-2009 debt crisis, the Federal Reserve Bank's continuing intervention in the debt markets creates artificially low long-term interest rates, and the resulting sharp decline in interest rates creates CAPM estimates that are simply implausible. In fact, during time periods in which Treasury yields are abnormally low due to various so called "black swan" factors, such as the COVID-19 pandemic and its current

and lasting effects on the output of the global economy, the accommodating and expansive Federal Reserve monetary policy during these crises, or periodic flight to quality episodes, normalizing the risk-free rate becomes a reasonable alternative.

Q. DR. MORIN, HOW DID YOU ESTIMATE THE NORMALIZED RISK-FREE RATE?

A. Normalizing the risk-free rate can be done in two ways. One expedient method is to smooth a historical time series of historical yields on 30-year Treasury bonds over a meaningful period. The smoothing process is accomplished using a moving average of 10 months. The graph below depicts the yield on long-term U.S. Treasury bonds from 2007 to 2021 (in blue) and the 10-month moving average yield (in red). As shown by the horizontal line on the graph, the average yield for the period is 3.3% which provides a reasonable estimate for the risk-free rate.



The second method to normalize the risk-free rate involves assembling the two building blocks of the risk-free rate as follows. The nominal risk-free rate can be seen as the sum of the inflation-free "real risk-free rate" and an inflation premium:[9]

RISK-FREE RATE = REAL RATE + EXPECTED INFLATION

To estimate expected inflation, one simply compares current real and nominal interest rates by looking at interest rates on comparable maturity Treasury securities, one that is not adjusted for inflation and one that is adjusted for inflation. So far in 2022, the yield on 30-year Treasury securities and the yield on 30-year inflation-protected Treasury securities, so-called "TIPS", has differed by 2.3%. The difference of 2.3% between the two yields over that period provides an estimate of expected inflation over the long-term.

There is an abundant of economic research literature on the real rate of interest[10] suggesting a consensus estimate in the 1.0% - 2.0% range with a recent trend towards the lower part of the range, 1.0%. Adding the long-term real risk-free rate of 1.0% to the expected long-term inflation of 2.3%, the normalized risk-free rate becomes 3.3% which also provides a reasonable estimate of the risk-free rate used in a CAPM analysis, in fact the same as the previous approach which also produced a normalized estimate of 3.3%.

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[9] This is the famed "Fisher equation", named after Irving Fisher. Fisher's "The Theory of Interest" was first published by Macmillan (New York), in 1930.

[10] See for example Taylor, J. B. and Wieland, V., "*Finding the Equilibrium Real Interest Rate in a Fog of Policy Deviations*," Hoover Institution Economics Working Papers, 2016; Kiley, M. T., "*The Global Equilibrium Real Interest Rate: Concepts, Estimates, and Challenges*," Finance and Economics Discussion Series Washington: Board of Governors of the Federal Reserve System, 2019-076, https://doi.org/10.17016/FEDS.2019.076.

Q. DR. MORIN, WHAT IS YOUR FINAL ESTIMATE OF THE APPROPRIATE RISK-FREE RATE TO BE USED IN A CAPM ANALYSIS?

A. My final estimate of the appropriate risk-free to be used in a CAPM analysis is 3.7%. This is based on the average of the consensus economic forecasts of 4.0% risk-free rate and the normalized risk-free estimate of 3.3%.

CAPM BETA ESTIMATE

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta" (β), or "systematic risk." The beta coefficient measures the change in a security's return relative to that of the market. The beta coefficient represents the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market. It measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements such as growth, leverage, and earnings volatility.

APS is not publicly traded. Therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity earlier, I examined a sample of investment-grade dividend-paying electric utilities covered by Value Line. The average beta for APS's proxy group is 0.87. Please see attachment RAM-05DR, for the beta estimates of the proxy group for APS. Based on these results, I shall use 0.87 as an estimate for the beta applicable

to APS. I note that the average beta estimate of 0.87 represents a dramatic increase in the average beta of the electric utility industry when compared to recent historical levels of 0.60 - 0.70. This is not surprising given the rising risks of the electric industry which I discuss earlier in my testimony.

CAPM MARKET RISK PREMIUM

Q. WHAT MRP DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the MRP, I used 8.0%. This estimate was based on the results of both historical and prospective studies of long-term risk premiums.

Q. CAN YOU DESCRIBE THE HISTORICAL MRP STUDY USED IN YOUR CAPM ANALYSIS?

A. Yes. The historical MRP estimate is based on the results obtained in Kroll's 2022 SBBI Yearbook (formerly published by Duff & Phelps and earlier by Morningstar and Ibbotson Associates), which compiles historical returns from 1926 to 2021. This well-known study summarized on Exhibit 6.8 of the handbook shows that a very broad market sample of common stocks outperformed long-term U.S. Government bonds by 6.3%. The historical MRP over the income component of long-term U.S. Government bonds, rather than over the total bond return, is 7.4%.

The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free. Moreover, the income component of total bond return (*i.e.*, the coupon rate) is a far better

estimate of expected return than the total return (*i.e.*, the coupon rate + capital gain), because both realized capital gains and realized losses are largely unanticipated by bond investors. The long-horizon (1926-2021) MRP is 7.4%.

Q. ON WHAT MATURITY BOND DOES THE KROLL HISTORICAL RISK PREMIUM DATA RELY?

A. Because 30-year bonds were not always traded or even available throughout the entire study period covered in the Kroll study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Given that the normal yield curve is virtually flat above maturities of 20 years for most of the period covered in the Kroll study, the difference in yield is not material.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MRP ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over shorter periods when estimating the MRP with historical returns. Therefore, a Risk Premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than expected are offset by short-run periods during which investors earned a higher risk premium than expected. Only over long-time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the

entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Since there is no evidence that the MRP in common stocks has changed over time, that is, no significant serial correlation in the Kroll study prior to that time, it is reasonable to assume that these quantities will remain stable in the future.

Q. SHOULD STUDIES OF HISTORICAL RISK PREMIUMS RELY ON ARITHMETIC AVERAGE RETURNS OR GEOMETRIC AVERAGE RETURNS?

A. Whenever relying on historical risk premiums, only arithmetic average returns over long periods are appropriate for forecasting and estimating the cost of capital. Geometric average returns are not appropriate.[11]

Q. PLEASE EXPLAIN HOW THE ISSUE OF WHETHER TO RELY ON THE ARITHMETIC OR GEOMETRIC MEAN ARISES WHEN ANALYZING THE COST OF EQUITY WITH HISTORICAL RETURNS.

A. The issue arises in applying methods that derive estimates of a utility's cost of equity from historical relationships between bond yields and earned returns on equity for individual companies or portfolios of several companies. Those methods produce series of numbers representing the annual difference between bond yields and stock returns over long

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[11] *See* Roger A. Morin, Ph.D., Modern Regulatory Finance, Chapter 5 (2022); Richard A. Brealey, et al., Principles of Corporate Finance (11th ed. 2014); Roger A. Morin, Ph.D., The New Regulatory Finance: Utilities' Cost of Capital, Chapter 4 (2006).

historical periods. The question is how to translate those series into a single number that can be added to a current bond yield to estimate the current cost of equity for a stock or a portfolio. Calculating geometric and arithmetic means are two ways of converting series of numbers to a single, representative figure.

Q. IF THE ARITHMETIC AND THE GEOMETRIC MEANS ARE BOTH "REPRESENTATIVE" OF THE SERIES, WHAT IS THE DIFFERENCE BETWEEN THE TWO MEANS?

A. Each mean represents different information about the series. The geometric mean of a series of numbers is the value which, if compounded over the period examined, would have made the starting value grow to the ending value. The arithmetic mean is simply the average of the numbers in the series. Where there is any annual variation (volatility) in a series of numbers, the arithmetic mean of the series, which reflects volatility, will always exceed the geometric mean, which ignores volatility. Because investors require higher expected returns to invest in a company whose earnings are volatile than one whose earnings are stable, the geometric mean is not useful in estimating the expected rate of return which investors require to make an investment.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE TO ILLUSTRATE THIS DIFFERENCE BETWEEN GEOMETRIC AND ARITHMETIC MEANS?

A. Yes. Figure 3 below compares the geometric and arithmetic mean returns of a hypothetical Stock A, whose yearly returns over a ten-year period are very volatile, with those of a hypothetical Stock B, whose yearly returns are perfectly stable during that period. Consistent with the point that geometric returns ignore volatility, the geometric mean returns for the two series are identical (11.6% in both cases), whereas the arithmetic mean

return of the volatile stock (26.7%) is much higher than the arithmetic mean return of the stable stock (11.6%).

If relying on geometric means, investors would require the same expected return to invest in both of these stocks, even though the volatility of returns in Stock A is very high while Stock B exhibits perfectly stable returns. That is clearly contrary to the most basic financial theory; that is, the higher the risk, the higher the expected return.

Chapter 5, Appendix A of my latest cost of capital textbook *Modern Regulatory Finance* contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. Briefly, the disparity between the arithmetic average return and the geometric average return raises the question as to what purposes should these different return measures be used. The answer is that the geometric average return should be used for measuring historical returns that are compounded over multiple time periods. The arithmetic average return should be used for future-oriented analysis, where the use of expected values is appropriate.

Figure 3: Arithmetic vs Geometric Mean Returns

Year	Stock A	Stock B
2012	50.0%	11.6%
2013	-54.7%	11.6%
2014	98.5%	11.6%
2015	42.2%	11.6%
2016	-32.3%	11.6%
2017	-39.2%	11.6%
2018	153.2%	11.6%
2019	-10.0%	11.6%
2020	38.9%	11.6%
2021	20.0%	11.6%
Std. Deviation	**64.9%**	**0.0%**
Arith. Mean	**26.7%**	**11.6%**
Geom. Mean	**11.6%**	**11.6%**

Q. CAN YOU DESCRIBE THE PROSPECTIVE MRP ESTIMATE USED IN YOUR CAPM ANALYSIS?

A. As a second estimate of the MRP, I examined Value Line's dividend yield and growth forecasts for the stocks in the S&P 500 Stock Index, that is, for the broad U.S. economy. Attachment RAM-06DR provides a prospective DCF analysis of the dividend-paying stocks that make up the S&P 500 Index using Value Line's screening software. The dividend yield (D_0/P) on the dividend-paying stocks in the S&P 500 Index is 2.4%, and the average projected long-term growth rate (g) is 9.6%. Adding the expected dividend yield (D_1/P) to the growth component produces an expected market return on aggregate equities of 12.2%. Subtracting the prospective risk-free rate of 3.7% from the latter, the implied risk premium is 8.5% over long-term U.S. Treasury bonds.

The average of the historical MRP of 7.4% and the prospective MRP of 8.5% is 8.0%, which is my final estimate of the MRP for purposes of implementing the CAPM.

Q. IS YOUR MRP ESTIMATE OF 8.0% CONSISTENT WITH THE ACADEMIC LITERATURE ON THE SUBJECT?

A. Yes, it is. Based on all the empirical evidence and the vast relevant literature on the subject, it is fair to conclude that a MRP range of 6% - 8% is a reasonable estimate for purposes of estimating the cost of equity with the CAPM in a regulatory setting. A slight preference for the upper end of the range is indicated during periods of capital market tumult such as the 2008-2009 credit crisis or the 2019-2022 Corona Virus pandemic.

The historical MRP approach is very simple and difficult to improve upon when you consider the variability and instability of the input data in alternative approaches. It is reasonable to conclude that over the long term, the MRP is likely to be similar to what it has been in the past.

In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[12] state:

"Many financial economists rely on the evidence of history and therefore work with a risk premium of about 7%. Brealey, Myers, and Allen have no official position on the issue, but we believe that a range of 5% to 8% is reasonable for the risk premium in the United States."

A similar sentiment is echoed by Professors Ross, Westerfield and Jordan (2013) in their well-known textbook, who cite:

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12 Richard A. Brealey, Stewart C. Myers, and Paul Allen, Principles of Corporate Finance, Irwin McGraw-Hill (11th ed. 2014).

"We are comfortable with an estimate based on the historical U.S. equity risk premium of about 7 percent, but estimates of the future U.S. equity risk premium that are somewhat higher or lower could be reasonable if we have good reason to believe the past is not representative of the future. The bottom line is that any estimate of the future equity risk premium will involve assumptions about the future risk environment as well as the amount of risk aversion of future investors". Page 326

My own survey of the MRP literature, which appears in Chapter 6 of my latest 2022 textbook, *Modern Regulatory Finance*, is also consistent with this consensus view.

Q. WHAT IS YOUR ESTIMATE OF APS'S COST OF EQUITY USING THE CAPM APPROACH?

A. Inserting those input values into the CAPM equation for each company in the group, namely a risk-free rate of 3.7%, the sample company's beta estimate, and a MRP of 8.0%, the average CAPM estimate of the cost of common equity for the group is 10.63%. This estimate becomes 10.83% with flotation costs, discussed later in my testimony. Please see attachment RAM-07DR for a detailed description of the CAPM analysis.

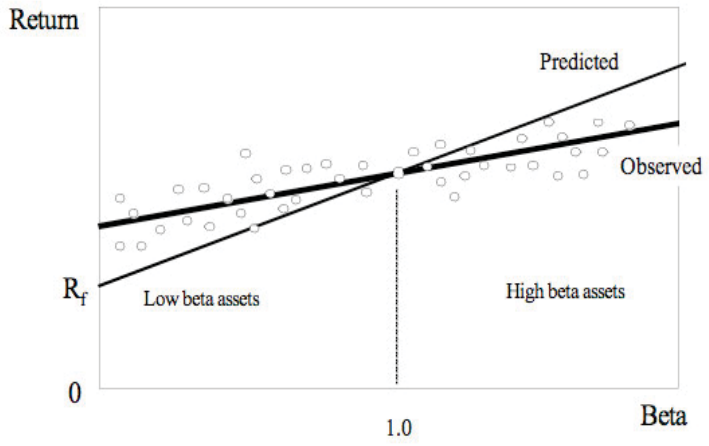
Q. CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION OF THE CAPM?

A. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 7 of my latest book, *Modern Regulatory Finance*. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research

has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance. It is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \times ((R_M - R_F) - \alpha)$$

where the symbol alpha, α, represents the "constant" of the risk-return line, MRP is the market risk premium (R_M - R_F), and the other symbols are defined as previously noted.

Inserting the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25 \times (R_M - R_F) + 0.75\beta \times (R_M - R_F)$$

An alpha range of one to two percent is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for lower-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effects of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas incorporates some of the desired effect of using the ECAPM.[13] Thus, it is reasonable to apply a conservative alpha adjustment. Please see attachment RAM-10DR for a discussion of the CAPM and the ECAPM.

In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25 (R_M - R_F) + 0.75 \times \beta \times (R_M - R_F)$$

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[13] The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line and Bloomberg betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% weight to the measured raw beta and 33% weight to the prior value of 1.0 for each stock: $\beta_{adjusted} = 0.33 + 0.66\ \beta_{raw}$

For each company in the group, inserting the risk-free rate of 3.7%, a MRP of 8.0% for (R_M - R_F) and the company's own beta estimate in the above equation, the average return on common equity for the group is 10.90%. This estimate becomes 11.10% with flotation costs, discussed later in my testimony. Please see attachment RAM-07DR for a detailed description of the ECAPM analysis.

Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. The reasoning to support the inconsistency argument is that the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. But this reasoning is erroneous.

Fundamentally, the ECAPM is not an adjustment, increase, or decrease in beta. The observed return on high beta securities is actually lower than that produced by the CAPM estimate, and conversely. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM, which adjusts the slope of the Capital Market Line, and the use of adjusted betas, which addresses the tendency of betas to regress to the value of 1.0, comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks and overstates the return for high beta stocks. And even if the ECAPM is used, the return for low-beta securities is understated if the betas are not adjusted for the tendency for betas to regress to the value of 1.0. Referring

back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. Figure 4 below summarizes the common equity estimates obtained from the CAPM studies.

Figure 4: CAPM Results

CAPM Method	ROE
Traditional CAPM	10.83%
Empirical CAPM	11.10%

C. Historical Risk Premium Estimates

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE UTILITY INDUSTRY USING TREASURY BOND YIELDS.

A. A historical risk premium for the utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1931-2021 period, using Standard and Poor's Utility Index (S&P Index) as an industry proxy. The risk premium was estimated by computing the actual realized ROE capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term Treasury bond return for that year. Please see attachment RAM-08DR, for an analysis of the historical risk premium for the utility industry using an annual time series analysis applied to the utility industry as a whole over the 1930-2021 period.

As shown on attachment RAM-08DR, the average risk premium over the period was 5.53% over long-term Treasury bond yields and 6.25% over the income component of bond yields. As discussed previously, the latter is the appropriate risk premium to use. Given the risk-free rate of 3.70%, and using the historical estimate of 6.25% for bond returns, the implied cost of equity is 3.70% + 6.25% = 9.95%. This estimate becomes 10.15% with flotation costs, discussed later in my testimony.

Q. ARE YOU CONCERNED ABOUT THE REALISM OF THE ASSUMPTIONS THAT UNDERLIE THE HISTORICAL RISK PREMIUM METHOD?

A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the Risk Premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would be reluctant to invest money.

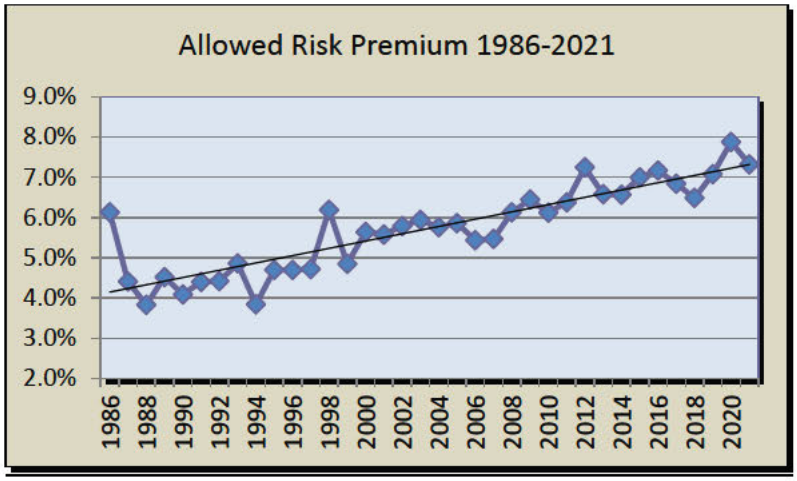
D. Allowed Risk Premium Estimates

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.

A. To estimate the electric and gas utility industry's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions utilities over the 1986-2021 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. Please see attachment RAM-09DR, for an analysis of historical risk premiums implied in the ROEs allowed by regulatory commissions utilities over the 1986-2021 period.

This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, CAPM, Risk Premium, etc.) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (now S&P Global Intelligence) and easily verifiable from prior issues of that same publication and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.7% over the entire 1986-2021 period for which data were available. The graph below shows the year-by-year allowed risk premium. The escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.



A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1986-2021 period:

$$RP = 8.2600 - 0.4822\ YIELD \qquad R^2 = 0.86$$

The relationship is highly statistically significant[14] as indicated by the very high R^2. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.

Inserting the long-term Treasury bond yield of 3.70% in the above equation suggests a risk premium estimate of 6.50%, implying a cost of equity of 10.18%. The latter

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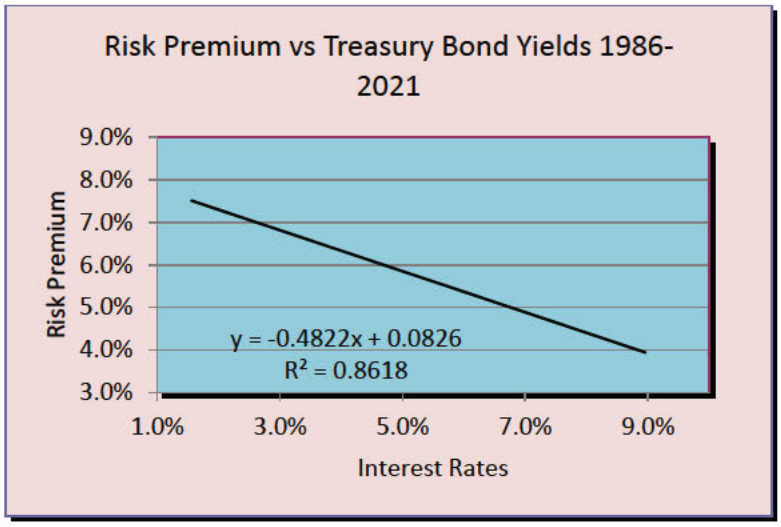
[14] The coefficient of determination R^2, sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data.

result is nearly identical to the 10.15% result obtained from the historical risk premium study.[15]



Q. DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN FORMULATING THEIR RETURN EXPECTATIONS?

A. Yes, among many other factors,investors do indeed take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and S&P Global Intelligence (formerly SNL and Regulatory Research Associates). Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns.

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[15] There is no need to adjust this figure for flotation cost given that the ROE data are based on allowed returns on book equity rather than on market-based returns.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. Figure 5 below summarizes the ROE estimates obtained from the two Risk Premium studies.

Figure 5: Risk Premium Estimates for APS

Risk Premium Method	ROE
Historical Risk Premium	10.15%
Allowed Risk Premium	10.18%

E. Need for Flotation Cost Adjustment

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that issuing common equity capital is not free. Flotation costs associated with stock issues are similar to the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (e.g., printing, legal, prospectus). The indirect

component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Attachment RAM-11DR to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether a company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation costs requires an upward adjustment to the allowed ROE.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.2%.

According to the empirical finance literature discussed in attachment RAM-11DR, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 20 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 4.0% for utility stocks by 0.95 yields 4.2%, which is 20 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair ROE, but only at the time when the expenses are incurred. In other words, as the argument goes, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure, although simple in implementation, is not considered appropriate,

however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. In the absence of valid reasons to do so, burdening the current generation of ratepayers with the full costs of raising capital is not preferable when the benefits of that capital extend indefinitely. The common practice of capitalizing rather than expensing eliminates the intergenerational transfers that would prevail if today's ratepayers were asked to bear the full burden of flotation costs of bond/stock issues in order to finance capital projects designed to serve future as well as current generations. Moreover, expensing flotation costs requires an estimate of the market pressure effect for each individual issue, which is likely to prove unreliable. A more reliable approach is to estimate market pressure for a large sample of stock offerings rather than for one individual issue.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to

capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. DR. MORIN, CAN YOU PLEASE ELABORATE ON THE MARKET PRESSURE COMPONENT OF FLOTATION COST?

A. The indirect component, or market pressure component, of flotation costs represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue, reflecting the basic economic fact that when the supply of securities is increased following a stock or bond issue, the price falls. The market pressure effect is real, tangible, measurable, and negative. According to the empirical finance literature cited in attachment RAM-11DR, the market pressure component of the flotation cost adjustment is approximately 1% of the gross proceeds of an issuance. The announcement of the sale of large blocks of stock produces a decline in a company's stock price, as one would expect given the increased supply of common stock.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE APS THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its owners, in this case, Pinnacle West. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

IV. SUMMARY OF RESULTS AND RECOMMENDATION

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final estimate of the cost of equity for APS's peer group, I performed the following analyses:

(i) a DCF analysis on a group of investment-grade dividend-paying electric utilities using Value Line's growth forecasts;

(ii) a DCF analysis on a group of investment-grade dividend-paying electric utilities using analysts' growth forecasts;

(iii) a traditional CAPM using current market data;

(iv) an empirical approximation of the CAPM using current market data;

(v) historical risk premium data from electric utility industry aggregate data, using the yield on long-term US Treasury bonds; and

(vi) allowed risk premium data from electric utility industry aggregate data, using the yield on long-term US Treasury bonds.

Figure 6 below summarizes the ROE estimates for APS's peer group.

Figure 6: Summary of ROE Estimates

STUDY	ROE
DCF Electric Utilities Value Line Growth	9.90%
DCF Electric Utilities Analysts Growth	9.29%
CAPM Electric Utilities	10.83%
Empirical CAPM Electric Utilities	11.10%
Historical Risk Premium Electric Utilities	10.15%
Allowed Risk Premium	10.18%

The average estimate is 10.24% and the truncated mean[16] is 10.27%. Based on those results, my recommended return is 10.25%

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in Figure 6 above must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from Figure 6 and infer the cost of common equity from that number alone.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING APS'S RETURN ON COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable ROE for APS's electric utility operations in the State of Arizona is 10.25%. I do consider my recommended ROE as conservative given the relative risks of the Company by virtue of its significant regulatory risks relative to that of its peers and significant external financing requirements over the next several years. Indeed, these risk circumstances point to an ROE above the central tendency of my analyses, and, therefore, an ROE of less than 10.25% would not be just and reasonable.

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[16] The truncated mean is obtained by removing the high and low results and computing the average of the remaining observations.

Q. DR. MORIN, PLEASE ELABORATE ON WHY YOU CONSIDER YOUR RECOMMENDED RETURN OF 10.25% CONSERVATIVE?

A. I consider my recommended return conservative for three reasons. The first reason is the heightened degree of APS' regulatory risk relative to that of its peers. The second reason is that the Company is very likely to raise very large sums of money in a rising interest rate environment over the next five years. The third reason is that the DCF results understate the Company's cost of equity in light of investors' flight to quality in the current capital and economic environment. I will now elaborate on each of these factors.

REGULATORY RISK

Q. CAN YOU COMMENT ON THE FIRST REASON AS TO WHY YOU CONSIDER YOUR ROE RECOMMENDATION BAREBONES?

A. The regulatory environment is highly uncertain in Arizona. The investment community has become concerned with the financial and policy implication of the Commission's last rate decision on November 9, 2021, and with the deterioration in the regulatory environment in Arizona. This has had an immediate and serious impact on the credit rating agencies' assessment of APS's regulatory risk and has inexorably led to an increase in the cost of capital, hence, on ratepayer burden.

Q. DR. MORIN, HOW DID THE INVESTMENT COMMUNITY REACT TO THE COMMISSION'S RECENT RATE CASE DECISION?

A. The reactions were swift and unequivocally negative. A series of credit downgrades and negative outlooks from all the credit rating agencies followed along with sell decisions from several equity analysts. On October 12, 2021, prior to the ACC decision of November

9, Fitch Ratings downgraded Pinnacle West and APS from A- to BBB+, with a Negative outlook. In summarizing its decision to downgrade, Fitch explained[17]:

> *"The one-notch rating downgrade and Negative Outlook for PNW and APS reflect anticipation of an adverse final order in APS's pending general rate case (GRC), resulting pressure on credit metrics and a heightened risk profile."*

Fitch went on to note that:

> *"Growing Regulatory Headwinds: Recent efforts by regulators to reduce rates, lower authorized returns and promote retail competition highlights the deterioration of the regulatory compact in Arizona. A series of recent decisions by the ACC that has delayed rate recovery and exacerbated regulatory lag have had negative implications for APS's and PNW's credit quality."*

Following the Commission decision on November 9, 2021, Moody's also downgraded Pinnacle West and APS from A- to BBB+, with a Negative outlook. In summarizing its decision to downgrade, Moody's explained[18]:

> *"The rate case decision will result in a base rate decrease of $119.8 million and a substantive decline in the authorized ROE to 8.7% from 10%, which is well below the national average of 9.5%. Additionally, the Arizona Corporation Commission (ACC) voted to disallow $215.5 million of the utility's selective catalytic reduction (SCR) investments made at the Four Corners plant in 2018 and also disallowed a grid access fee charge. These results are indicative of a less credit supportive and predictable regulatory framework in Arizona compared to the rest of the country, materially increasing regulatory risk for both Pinnacle and APS going forward."*

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[17] FitchRatings, Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative, Oct. 12, 2021

[18] Moody's Investor Services Credit Opinion, Rating Action: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative, Nov. 17, 2021.

Moody's went on to note that:

> *"The negative outlook reflects increased regulatory risk, uncertainty over future rate case filings, and the lack of financial flexibility as credit metrics have fallen. APS is operating in a more challenging regulatory jurisdiction, could experience higher scrutiny over future investments and may face disallowances of other cost recovery mechanisms given the ACC's focus on customer affordability".*

On November 4, 2021, in its review of the electric utility industry, Moody's noted[19]:

> *Despite the mostly positive environment, there have been some notable exceptions, including credit negative regulatory actions in Arizona, Connecticut and New York. On 12 October, for example we placed the ratings of Pinnacle West Capital Corporation (A3) and its principal subsidiary Arizona Public Service Company (APS, A2) on review for downgrade in the wake of a contentious rate case proceeding before the Arizona Corporation Commission, which voted to lower the utility's ROE and to consider material cost recovery disallowances.*

On November 9, 2021, S&P also downgraded Pinnacle West and APS from A- to BBB+, with a Negative outlook. In summarizing its decision to downgrade, S&P explained[20]:

> *"The Arizona Corporation Commission (ACC) recently voted to lower Pinnacle West Capital Corp. (PWCC) utility subsidiary Arizona Public Service's (APS') return on equity (ROE) to 8.7%, and denied cost recovery of about $216 million in pollution control costs at the Four Corners coal-fired power plant".*

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[19] Moody's Investor Services, "2022 outlook stable on sustained regulatory support for robust investment cycle", Nov.4, 2021.

[20] Standard & Poors Ratings Direct, Pinnacle West Capital Corp. Downgraded To 'BBB+', Outlook Negative, On Arizona Rate Reduction, Nov. 9, 2021.

S&P went on to note that:

"The downgrade and negative outlook reflects higher regulatory risk in Arizona. The downgrade on PWCC and its subsidiary reflects the ACC's final order, including lower authorized ROE to 8.7%, resulting in a base rate reduction of about $119 million (total rate decrease of about $5 million) and denial of recovery of $216 million of pollution control investment. We expect the credit metrics at PWCC will remain below our downside trigger of 18% over the next two years, reflecting the regulatory lag from the lower ROE and disallowance of investment and cost recovery".

"Our negative outlook reflects our expectation that the regulatory overhang regarding the authorized ROE and cost recovery add uncertainty to PWCC's credit risk profile."

Pinnacle West's common stock didn't fare much better. On October 7, 2021, Guggenheim double downgraded Pinnacle West to a Sell recommendation, and stated[21]:

"We are downgrading PNW two notches to SELL from BUY. This negative revision in our thesis represents a forward fundamental deterioration call, a negative earnings revision call, incremental equity/balance sheet worsening call, a call that reflects the state of AZ being the most value destructive state in the country including within our +40 utilities under coverage."

In its November 5, 2021 report, S&P stated[22]:

"The commission on Nov. 2 voted to cut the utility's rate of return on equity to 8.7% and disallowed a $215.5 million recovery of pollution control costs at the Four Corners coal-fired power plant in a controversial case that has seen Pinnacle West stock plunge over 14% since mid-October."

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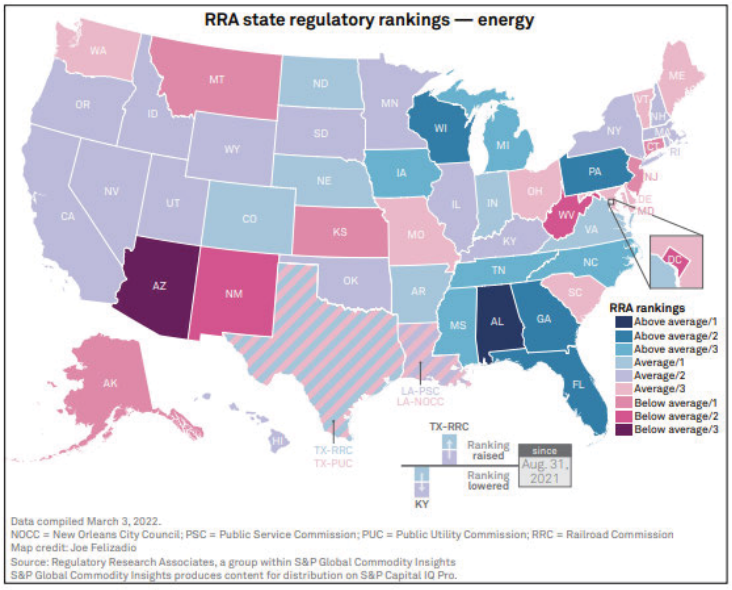
[21] StreetInsider.com, "Guggenheim Double Downgrades Pinnacle West Capital (PNW) to Sell", 10/7/21.

[22] S&P Global Market Intelligence, "Pinnacle West details equity plan after Ariz. regulators puncture balance sheet," Nov. 5, 2021.

Recently on March 10, 2022, in its quarterly State Regulatory Evaluations, RRA downgraded ACC regulation to "Below Average /3" which is at the bottom of the rankings in the nation[23]. The graph below displays the state-by-state assessment of regulation in the U.S.



Moreover, all three rating agencies have not only downgraded the Company's bonds but also placed its bonds under negative outlook for possible further downgrades.

In short, regulatory decisions unsupportive of the Company's credit and financial integrity have increased the Company's risk profile and have led to APS's credit rating downgrade from all three credit rating agencies. These downgrades have increased the

[23] RRA Regulatory Focus, Quarterly State Regulatory Evaluations, "RRA State Regulatory Evaluations — Energy," March 10, 2022.

Company's cost of capital, and thus, ultimately, the rates that customers will be required to pay on future debt and equity issues.

As a result of the Commission's recent actions and the investment community's reactions, APS may be sliding down a slippery slope. Here is the dilemma. The Company has to keep funding the the assets and infrastructure to provide electric service to meet the growing needs in the state. But equity investors will naturally be reluctant to invest in new issues of Pinnacle West common stock following the Commission's last punitive rate order, in which case APS may have to lever (raise debt capital) the company further in order to raise the needed capital as a lower investment grade company. This will in turn increase financial risk, increase the cost of debt and the cost of equity, and so on.

Q. ARE THERE ADDITIONAL REGULATORY RISK FACTORS THAT POTENTIONALLY ACCENTUATE REGULATORY RISKS THAT THE COMMISSION SHOULD CONSIDER?

A. Yes, there are additional factors that potentially accentuate the Company's regulatory risks relative to its peers and should be considered by the Commission: (1) test year policy, and (2) CWIP treatment.

First, with regard to the use of historical test year used by the Commission, APS's exposure to regulatory lag remains substantial relative to other utilities that rely on future test years for ratemaking. The problem of regulatory lag is well-known in the utility industry and is particularly acute in the case of APS on account of the Commission's use of a historical test year in setting rates. The use of a historical test year makes it difficult to earn a reasonable rate of return, especially in an inflationary environment, or where, as is the case presently, significant levels of infrastructure investment are anticipated. In the

case of APS, the company has not been able to earn its allowed rate of return in four of the last five years, in part due to the use of a historical test year. Both inflation and large investments serve to erode return in a low growth environment. This problem can only be exacerbated if conservation and/or distributed generation create sales declines that are not addressed through appropriate regulatory mechanisms. Regulatory lag also creates mismatches between regulatory rates and supply-demand-costs so that rates are either too high or too low. Inefficient resource allocation and distorted consumer pricing signals may result. One expedient solution to the regulatory lag issue is the use of a forward, or future, test year rather than an historical test year.

Second, although it does allow some CWIP amount for post test year plant, the Commission does not allowed the inclusion of all the CWIP in rate base, as I believe it should. Because inclusion of CWIP in rate base helps to support cash flow metrics during a large construction cycle such as the one the Company is facing over the next five years, the investment community views the inclusion of CWIP in rate base for a cash return as supportive regulation and risk-mitigating. The alternative which is for the utility to accrue allowance for funds used during construction (AFUDC), does not augment cash flow and does not support the financial credit metrics scrutinized by credit rating agencies when assigning credit rating. By allowing the Company to include the interest on debt and a return on investor's equity (known as carrying costs) in rates while the capital assets are under construction, the Company's risk is reduced. CWIP actually lowers the risks to

ratepayers because it makes capital projects more affordable to build, "paying it forward" so to speak, increasing the chance of successfully completing projects[24].

Q. GIVEN THE DETERIORATION IN THE ARIZONA REGULATORY CLIMATE AND THE POTENTIAL CONCOMITANT INCREASE IN RISK AND COST OF CAPITAL, DO YOU HAVE ANY RECOMMENDATION FOR THE COMMISSION IN THAT REGARD?

A. Yes, I do. While I fully sympathize and agree with the Commission's goal of ensuring affordable customer rates, authorizing a ROE less than the cost of equity capital, in fact the lowest ROE allowed for US-based vertically-integrated electric utilities in the nation, has the opposite effect. This is because the Company has substantial capital needs over the next five years and it will be forced to incur much higher cost of capital to raise those funds than otherwise would be the case if the Commission had authorized a return in keeping with the returns offered by comparable risk utility investments.

[24] The allowed rate of return on equity and the inclusion of CWIP in the rate base are particularly significant to investors in measuring the regulatory climate for public utilities. Not surprisingly, the preponderance of the empirical evidence supports the notion that a favorable regulatory climate decreases a utility's risk and capital costs. This large body of evidence is summarized in Morin, R.A., "Modern Regulatory Finance," PUR Books, Inc., 2022, Chapter 4.6.

Q, DR. MORIN, PLEASE PROVIDE A SIMPLE NUMERICAL EXAMPLE SHOWING WHAT HAPPENS TO RATEPAYERS WHEN A COMPANY'S BONDS ARE DOWNGRADED FROM SINGLE A TO BBB.

A. The following example shows that the ratepayer burden and the cost of capital would increase significantly. Let's say the Company issues a 20-year $100 million bond. The difference in cost between being a single A-rated company and being a BBB-rated company is approximately 30 basis points (0.30%) based on historical spreads between A and BBB bonds, that is, the cost of debt increases by 30 basis points. So, every year for 20 years, the additional cost to ratepayers is $300,000 (0.30% times $100 million) per year. Over the entire 20-year period, the total additional cost to ratepayers is therefore $6 million (20 times $300,000). This example is conservative, for it does not even consider the increase in common equity capital costs.

To reiterate, for every $100 millions of bonds issued by the company, the additional cost to ratepayers of being a BBB company instead of being a single A company is $6 million over 20 years. In the specific case of APS, the Company's projected capital budget is approximately $7.2 billion over the next five years, of which at least 50% is to come from debt financing, that is, $3.6 billion. From the above computation, the additional cost to ratepayers is a staggering $216 million from being a lower-rated company, let alone the increase in cost of common equity[25].

[25] $3.6 billion divided by $100 million times $6 million equals $216 million.

OPTIMAL BOND RATING

Q. DR. MORIN, WHAT IS THE OPTIMAL BOND RATING FOR A REGULATED UTILITY?

A. A single A bond rating generally results in the lowest pre-tax cost of capital for regulated utilities, and therefore the lowest ratepayer burden, especially under adverse economic conditions, which are far more relevant to the question of capital structure. This result prevails over a wide range of cost of common equity models and estimates utilized, and remains robust to changes in key assumptions.

As I showed in the optimal capital structure simulation model developed in Chapter 19 of my book *Modern Regulatory Finance*, a strong single A bond rating will minimize the pre-tax cost of capital to ratepayers. Long-term achievement/retention of a single A bond rating is in both the utility's and ratepayers' best interests. If the company maintains its debt ratio within the optimal range discussed earlier for an A-rated company, its overall cost of capital should be minimized. If the company reduces its debt ratio below that point, it would be giving up the tax benefits associated with debt but would not reap the benefits from a lower cost of debt and equity. If the company operates at a debt ratio beyond that point, the cost of debt and equity will rise, and therefore so will the cost of service.

Earlier in my testimony, I showed that the cost to ratepayers of being a BBB company instead of being a single A company is $6 million for every $100 million of bonds issued by the company. Besides the aforementioned substantial increase in ratepayer burden, existing bondholders incur a capital loss with the attendant rise in the cost of debt, and the cost of common equity capital rises as well. Thus, it is imperative that the Commission be supportive in order for the Company to regain its single A rating and avoid

the aforementioned consequences. Approval of my recommended ROE would certainly increase the probability of upgrading the Company's financial integrity and regaining its single A bond rating which I consider optimal.

Q. SHOULD CUSTOMERS BE CONCERNED WITH APS'S ALLOWED ROE AND WITH THE ARIZONA REGULATORY CLIMATE GENERALLY?

A. Yes, they certainly should. We have seen first-hand how unreasonably low allowed ROEs and disallowances have cause the credit agencies to downgrade APS's credit rating. This in turn has increased borrowing costs which are a direct pass through to customers. This is crucial over the next five years as APS will be raising substantial amounts of capital in a rising interest rate environment.

The bottom line is that a financially strong utility with an allowed return reflective of its true cost of capital benefits customers because an investment-grade financially strong utility will be able to invest in key capital investment initiatives and new technologies that benefits customers, while also keeping the Company's cost of capital and customer bills affordable as well.

EXTERNAL FINANCING RISKS

Q. CAN YOU COMMENT ON THE SECOND REASON WHY YOU CONSIDER YOUR ROE RECOMMENDATION CONSERVATIVE?

A. Yes. The Company is projected to need to raise large sums of money in a rising interest rate environment and highly uncertain regulatory environment over the next five years. The Company's capital expenditure program will require approximately $7.5 billion of financing over the next five years mostly for new utility infrastructure investments in grid modernization and investments in cleaner energy. To place that number in proper

perspective, the Company's common equity balance is approximately $5.2 billion and its total capitalization base is approximately $10.1 billion. In other words, the Company is expected to spend an amount that exceeds its entire common equity ownership capital by nearly 50%, and increase its total capitalization base over the next five years by almost 77%.

Because of the Company's anticipated construction program relative to its rate base and owners' capital (common equity balance) over the next few years, rate relief requirements and regulatory treatment uncertainty will increase regulatory risks as well. Generally, regulatory risks include approval risks, lags and delays, potential rate base exclusions, and potential disallowances. Continued regulatory support from the Commission will be required.

Q. ARE CREDIT RATING AGENCIES AWARE OF THE RISKS ASSOCIATED WITH ELEVATED LEVELS OF CAPITAL EXPENDITURES?

A. Yes, they are. As far as credit agencies are concerned, high levels of capital expenditures exert additional pressure on free cash flows and other financial metrics analyzed by analysts and, therefore, on credit ratings. It will be important to ensure that the Company's credit metrics are supported through the capital structure and an authorized ROE equal to that of my recommended return.

DCF UNDERSTATEMENT

Q. CAN YOU COMMENT ON THE THIRD REASON WHY YOU CONSIDER YOUR ROE RECOMMENDATION CONSERVATIVE?

A. DCF estimates may well understate investor return requirements in the current economic environment. Economic uncertainty in the face of rising interest rates, record-high inflation

rates, a declining economic environment, and the potential for economic stagflation, has precipitated a flight to quality which has driven utility dividend yields lower. That relationship makes intuitive sense; as investors see increasing risk, their objectives may shift principally to capital preservation, that is, avoiding capital losses. One method of doing so is to allocate capital to the relative safety of utility stocks in a "flight to safety." In those instances, the fall in utility dividend yields does not reflect a reduction in required returns, but rather reflects an increase in risk aversion and, therefore, an increase in investor-required returns. Hence the need to rely on a variety of methodologies when estimating the cost of equity capital and not place undue weight on DCF results.

Q. DR. MORIN, WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON APS'S COMMON EQUITY CAPITAL?

A. My recommended return on common equity for APS is predicated on the adoption of a pro- forma capital structure consisting of approximately 52% common equity capital. The Company's requested overall cost of capital, including my ROE recommendation is discussed below.

Q. WHAT CAPITAL STRUCTURE AND WEIGHTED AVERAGE COST OF CAPITAL ARE YOU RECOMMENDING TO THE COMMISSION IN THIS PROCEEDING?

A. The calculation of the test year capital structure and any post test year pro-formas are contained on Schedule D-1 that is included in the required filing requirements. A summary of the capital structure and the overall weighted average cost of capital is shown below.

Figure 7: Arizona Public Service Company Weighted Average Cost of Capital Test Year Ended June 30, 2022

Line No.	(a) Component	(b) Weight	(c) Cost	(d) Weighted Average Cost
1	Long-Term Debt	48.07%	3,85%	1.85%
2	Preferred Stock	0.00%	0.00%	0.00%
3	Common Equity	51.93%	10.25%	5.32%
4	TOTALS	100.00%		7.17%

Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. WERE ATTACHMENTS RAM-01DR TO RAM-11DR PREPARED BY YOU AND/OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes, they were.

FAIR VALUE STANDARD

Q. DR. MORIN, ARE YOU AWARE OF THE FAIR VALUE STANDARD IN ARIZONA?

A. Yes, I am. As the Commission noted in the *Chaparral City Water Company* case (Decision No. 70441 (July 28,2008), at 20-21.) the Arizona Constitution requires the use of a fair value rate base in establishing rates. Article XV, Section 14 of the Arizona Constitution states:

> *The corporation commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein; and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.*

This paragraph requires the Commission to find the fair value of a public service corporation's property and to use that value to set just and reasonable rates.

Q. HOW HAS THE COMMISSION APPLIED THE FAIR VALUE STANDARD IN PRIOR CASES?

A. In recent cases the Commission includes the calculation of two components: (1) the fair value rate base; and (2) the fair value rate of return on the fair value rate base.

Q. WHAT HAS BEEN THE COMMISSION'S POLICY FOR DETERMINING THE RATE OF RETURN TO BE APPLIED TO THE FAIR VALUE INCREMENT ?

A. The Commision first calculates a fair value increment (FVI) by determining the difference between the Original Cost Rate Base and the Fair Value Rate Base. The Commission has typically authorized a return on the fair value increment by utilizing the risk-free interest rate as a benchmark. I discussed the derivation of the risk-free rate in my CAPM testimony above. My conclusion was that a risk-free rate of 3.7% was appropriate at this point in time. It is my understanding that the Company is proposing to utilize a 1% return for the fair value increment of the a fair value capital structure.

Q. YOU PREVIOUSLY TESTIFIED THAT THE REAL RISK FREE RATE WAS THE DIFFERENCE BETWEEN THE NOMIAL RISK FREE RATE AND THE EXPECTED RATE OF INFLATION. IF YOUR ESTIMATE OF THE NOMINAL RISK FREE RATE IS 3.7% AND INFLATION IS CURRENTLY ESTIMATED TO BE IN EXCESS OF 8%, DOESN'T THAT IMPLY A REAL RISK FREE RATE THAT IS NEGATIVE?

A. The situation hypothesized in this question incorrectly mixes a long-term expected yield with a short-term historical result. As I previously testified the appropriate nominal risk free rate is a rate that embodies an estimate of long-term inflation expectations. A long-term expected nominal risk free rate is needed because the assets involved are long-lived assets and these assets are financed with common stock and bonds that are long-term instruments. Therefore, use of a current historical inflation estimate is inconsistent with the long-term inflation expectation already embedded in the estimate of the nominal real rate of return.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

RESUME OF ROGER A. MORIN

(SUMMER 2022)

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Fernandina Beach, FL 32034

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Indian Harbour
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TELEPHONE: (904) 844-2412 business office
(404) 229-2857 cellular
(902) 823-0000 summer office

E-MAIL ADDRESS: profmorin@mac.com

EMPLOYER 1980-2022: Georgia State University
Robinson College of Business
University Plaza
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3

- Assistant Professor, University of Montreal School of Business, 1973-1976.

- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2012

- Emeritus Professor of Finance, Georgia State University 2012-present

- Distinguished Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2011

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.

- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.

- Co-founder and Director Canadian Finance Research Foundation, 1977.

- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.

- Member Board of Directors, Executive Visions Inc., 1985-2021

- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.

- Member Board of Directors, Hotel Equities Inc., 2009-2022

PROFESSIONAL CLIENTS

AGL Resources
AT & T Communications
Alagasco - Energen
Alaska Anchorage Municipal Light & Power
Alberta Power Ltd.
Allete
Alliant Energy
AmerenUE
American Water
Ameritech
Arkansas Western Gas
ATC Transmission
Baltimore Gas & Electric – Constellation Energy
Bangor Hydro-Electric
B.C. Telephone
B C GAS
Bell Canada

Bellcore
Bell South Corp.
Bruncor (New Brunswick Telephone)
Burlington-Northern
C & S Bank
California Pacific
Cajun Electric
Canadian Radio-Television & Telecomm. Commission
Canadian Utilities
Canadian Western Natural Gas
Cascade Natural Gas
Centel
Centra Gas
Central Illinois Light & Power Co
Central Telephone
Central & South West Corp.
CH Energy
Chattanooga Gas Company
Cincinnatti Gas & Electric
Cinergy Corp.
Citizens Utilities
City Gas of Florida
Cleco Power
CN-CP Telecommunications
Commonwealth Telephone Co.
Columbia Gas System
Consolidated Edison
Consolidated Natural Gas
Constellation Energy
Delmarva Power & Light Co
Deerpath Group
Detroit Edison Company
Dayton Power & Light Co.
DPL Energy
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
Duke Energy Progress South Carolina
Duke Energy Progress North Carolina
DTE Energy
Edison International
Edmonton Power Company
Elizabethtown Gas Co.
Emera
Energen
Engraph Corporation

Entergy Corp.
Entergy Arkansas Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi Power
Entergy New Orleans, Inc.
Federal Energy Regulatory Commission
First Energy
Florida Water Association
Fortis
Garmaise-Thomson & Assoc., Investment Consultants
Gaz Metropolitain
General Public Utilities
Georgia Broadcasting Corp.
Georgia-Pacific
Georgia Power Company
GTE California - Verizon
GTE Northwest Inc. - Verizon
GTE Service Corp. - Verizon
GTE Southwest Incorporated - Verizon
Gulf Power Company
Havasu Water Inc.
Hawaiian Electric Company
Hawaiian Elec & Light Co
Heater Utilities – Aqua - America
Hope Gas Inc.
Hydro-Quebec
ICG Utilities
Interstate Power & Light
Illinois Commerce Commission
Interstate Power & Light
Island Telephone
ITC Holdings
Jersey Central Power & Light
Kansas Power & Light
KeySpan Energy
Maine Public Service
Manitoba Hydro
Maritime Telephone
Maui Electric Co.
Metropolitan Edison Co.
Minister of Natural Resources Province of Quebec
Minnesota Power & Light
Mississippi Power Company
Missouri Gas Energy
Mountain Bell

National Grid PLC
Nevada Power Company
New Brunswick Power
Newfoundland Power Inc. - Fortis Inc.
New Market Hydro
New Mexico Gas Co.
New Tel Enterprises Ltd.
New York Telephone Co.
NextEra Energy
Niagara Mohawk Power Corp
Norfolk-Southern
Northeast Utilities
Northern Telephone Ltd.
Northwestern Bell
Northwestern Utilities Ltd.
Nova Scotia Power
Nova Scotia Utility and Review Board
NUI Corp.
NV Energy
NYNEX
Oklahoma Gas & Electric
Ontario Telephone Service Commission
Orange & Rockland
PNM Resources
PPL Corp
PacifiCorp
Pacific Northwest Bell
People's Gas System Inc.
People's Natural Gas
Pennsylvania Electric Co.
Pepco Holdings
Potomac Electric Power Co.
PSI Energy
Public Service Electric & Gas
Public Service of New Hampshire
Public Service of New Mexico
Puget Sound Energy
Quebec Telephone
Regie de l'Energie du Quebec
Rockland Electric
Rochester Telephone
SNL Center for Financial Execution
San Diego Gas & Electric
SaskPower
Sempra
Sierra Pacific Power Company

Southern California Gas Company
Source Gas
Southern Bell
Southern California Gas
Southern States Utilities
Southern Union Gas
South Central Bell
Sun City Water Company
TECO Energy
The Southern Company
Touche Ross and Company
TransEnergie
Trans-Quebec & Maritimes Pipeline
TXU Corp
US WEST Communications
Union Heat Light & Power
Utah Power & Light
Vermont Gas Systems Inc.
Wisconsin Power & Light

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73

- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75

- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78

- Investment Dealers Association of Canada, 1977-78

- Financial Research Foundation, bi-annual seminar, 1975-79

- Advanced Management Research (AMR), faculty member, 1977-80

- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

- The Management Exchange Inc., faculty member 1981-2008:

  National Seminars: *Risk and Return on Capital Projects*
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Fundamentals of Utility Finance
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education faculty member 2008-2018

- S&P Global Intelligence, faculty member 2015 -2022
  National Seminars: *Essentials of Utility Finance*

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance
Rate of Return
Capital Structure
Generic Cost of Capital
Costing Methodology
Depreciation
Flow-Through vs Normalization
Revenue Requirements Methodology
Utility Capital Expenditures Analysis
Risk Analysis
Capital Allocation
Divisional Cost of Capital, Unbundling
Incentive Regulation & Alternative Regulatory Plans
Shareholder Value Creation
Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission
Alaska Regulatory Commission
Alberta Public Service Board
Arizona Corporation Commission
Arkansas Public Service Commission
British Columbia Board of Public Utilities
California Public Service Commission
Canadian Radio-Television & Telecommunications Comm.
City of New Orleans Council
Colorado Public Utilities Commission
Colorado Department of Revenue
Delaware Public Service Commission
District of Columbia Public Service Commission
Federal Communications Commission
Federal Energy Regulatory Commission
Florida Public Service Commission
Georgia Public Service Commission
Georgia Senate Committee on Regulated Industries
Hawaii Public Utilities Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Louisiana Public Service Commission

Maine Public Utilities Commission
Manitoba Board of Public Utilities
Maryland Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Missouri Public Service Commission
Montana Public Service Commission
National Energy Board of Canada
Nebraska Public Service Commission
Nevada Public Utilities Commission
New Brunswick Board of Public Commissioners
New Hampshire Public Utilities Commission
New Jersey Board of Public Utilities
New Mexico Public Regulation Commission
New Orleans City Council
New York Public Service Commission
Newfoundland Board of Commissioners of Public Utilities
North Carolina Utilities Commission
North Dakota Public Service Commission
Nova Scotia Board of Public Utilities
Ohio Public Utilities Commission
Oklahoma Corporation Commission
Ontario Telephone Service Commission
Ontario Energy Board
Oregon Public Utility Service Commission
Pennsylvania Public Utility Commission
Quebec Regie de l'Energie
Quebec Telephone Service Commission
South Carolina Public Service Commission
South Dakota Public Utilities Commission
Tennessee Regulatory Authority
Texas Public Utility Commission
Utah Public Service Commission
Utah State Tax Commission
Vermont Department of Public Services
Virginia State Corporation Commission
Washington Utilities & Transportation Commission
West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C
Southern Bell, So. Carolina PSC, Docket #82-294C
Southern Bell, North Carolina PSC, Docket #P-55-816
Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250
Georgia Power, Georgia PSC, Docket # 3270-U, 1981
Georgia Power, Georgia PSC, Docket # 3397-U, 1983
Georgia Power, Georgia PSC, Docket # 3673-U, 1987
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Bell Canada, CRTC 1987
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GTE-Quebec Telephone, Quebec PSC, Docket 84-052B
Newtel., Newfoundland Board of Public Commission, PU 11-87
CN-CP Telecommunications, CRTC
Quebec Northern Telephone, Quebec PSC
Edmonton Power Company, Alberta Public Service Board
Kansas Power & Light, F.E.R.C., Docket # ER 83-418
NYNEX, FCC generic cost of capital Docket #84-800
Bell South, FCC generic cost of capital Docket #84-800
American Water Works - Tennessee, Docket #7226
Burlington-Northern - Oklahoma State Board of Taxes
Georgia Power, Georgia PSC, Docket # 3549-U
GTE Service Corp., FCC Docket #84-200
Mississippi Power Co., Miss. PSC, Docket U-4761
Citizens Utilities, Ariz. Corp. Comm., Docket U2334-86020
Quebec Telephone, Quebec PSC, 1986, 1987, 1992
Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991
Northwestern Bell, Minnesota PSC, Docket P-421/CI-86-354
GTE Service Corp., FCC Docket #87-463
Anchorage Municipal Power & Light, Alaska PUC, 1988
New Brunswick Telephone, N.B. PUC, 1988
Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92
Gulf Power Co., Florida PSC, Docket #88-1167-EI
Mountain States Bell, Montana PSC, #88-1.2
Mountain States Bell, Arizona CC, #E-1051-88-146
Georgia Power, Georgia PSC, Docket # 3840-U, l989
Rochester Telephone, New York PSC, Docket # 89-C-022
Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89
GTE Northwest, Washington UTC, #U-89-3031
Orange & Rockland, New York PSC, Case 89-E-175
Central Illinois Light Company, ICC, Case 90-0127
Peoples Natural Gas, Pennsylvania PSC, Case
Gulf Power, Florida PSC, Case # 891345-EI
ICG Utilities, Manitoba BPU, Case 1989
New Tel Enterprises, CRTC, Docket #90-15
Peoples Gas Systems, Florida PSC
Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J
Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board
Mountain Bell, Utah PSC,
Mountain Bell, Colorado PUB
South Central Bell, Louisiana PS
Hope Gas, West Virginia PSC
Vermont Gas Systems, Vermont PSC
Alberta Power Ltd., Alberta PUB
Ohio Utilities Company, Ohio PSC
Georgia Power Company, Georgia PSC
Sun City Water Company
Havasu Water Inc.
Centra Gas (Manitoba) Co.
Central Telephone Co. Nevada
AGT Ltd., CRTC 1992
BC GAS, BCPUB 1992
California Water Association, California PUC 1992
Maritime Telephone 1993
BCE Enterprises, Bell Canada, 1993
Citizens Utilities Arizona gas division 1993
PSI Resources 1993-5
CILCORP gas division 1994
GTE Northwest Oregon 1993
Stentor Group 1994-5
Bell Canada 1994-1995
PSI Energy 1993, 1994, 1995, 1999
Cincinnati Gas & Electric 1994, 1996, 1999, 2004
Southern States Utilities, 1995
CILCO 1995, 1999, 2001
Commonwealth Telephone 1996
Edison International 1996, 1998
Citizens Utilities 1997
Stentor Companies 1997
Hydro-Quebec 1998
Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003
Detroit Edison, 1999, 2003
Entergy Gulf States, Texas, 2000, 2004
Hydro Quebec TransEnergie, 2001, 2004
Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010
Nevada Power Company, 2001
Mid American Energy, 2001, 2002
Entergy Louisiana Inc. 2001, 2002, 2004
Mississippi Power Company, 2001, 2002, 2007
Oklahoma Gas & Electric Company, 2002 -2003
Public Service Electric & Gas, 2001, 2002
NUI Corp (Elizabethtown Gas Company), 2002
Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002, 2012, 2014
New Brunswick Power, 2002
Entergy New Orleans, 2002, 2008
Hydro-Quebec Distribution 2002
PSI Energy 2003
Fortis – Newfoundland Power & Light 2002
Emera – Nova Scotia Power 2004
Hydro-Quebec TransEnergie 2004
Hawaiian Electric 2004
Missouri Gas Energy 2004
AGL Resources 2004
Arkansas Western Gas 2004
Public Service of New Hampshire 2005
Hawaiian Electric Company 2005, 2008, 2009
Delmarva Power & Light Company 2005, 2009
Union Heat Power & Light 2005
Puget Sound Energy 2006, 2007, 2009
Cascade Natural Gas 2006
Entergy Arkansas 2006-7
Bangor Hydro 2006-7
Delmarva 2006, 2007, 2009
Potomac Electric Power Co. 2006, 2007, 2009
Duke Energy Ohio, 2007, 2008, 2009
Duke Energy Kentucky 2009
Consolidated Edison 2007 Docket 07-E-0523
Duke Energy Ohio Docket 07-589-GA-AIR
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Sierra Pacific Power Docket ER07-1371-000
Public Service New Mexico Docket 06-00210-UT
Detroit Edison Docket U-15244
Potomac Electric Power Docket FC-1053
Delmarva, Delaware, Docket 09-414
Atlantic City Electric, New Jersey, Docket ER-09080664
Maui Electric Co, Hawaii, Docket 2009-0163, 2011
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Sierra Pacific Power Docket No. 10-06001
Gaz Metro, Regie de l'Energie (Quebec), Docket 2012 R-3752-2011
California Pacific Electric Co., LLC, California PUC, Docket A-12-02-014
Duke Energy Ohio, Ohio Case No. 11-XXXX-EL-SSO
San Diego Gas & Electric, FERC, 2012, 2014, 2018
San Diego Gas & Electric, California PUC, 2012, Docket A-12-04
Southern California Gas, California PUC, 2012, Docket A-12-04
Puget Sound Electric 2016
Puget Sound Electric 2017
Duke Energy of Ohio 2015, 2018
Duke Energy of Kentucky 2017. 2018

Duke Energy of Ohio 2017
Dayton Power & Light 2016-2018
Missouri American Water
California Power Electric Company
Interstate Power & Light Iowa 2017, 2018
Wisconsin Power & Light 2016
OG&E Electric 2018
Duke Energy Kentucky 2019
IPL Iowa 2019
Puget Sound Electric 2019
SDG&E California 2019
SDG&E FERC 2019
Southern California Gas 2019
Entergy Louisiana Inc. 2020-2021
Cleco Power 2021
PacifiCorp 2021

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fl, 1988.

- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, l978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Mgt Ass, 1985-1986

- Reviewer: Journal of Financial Research, Financial Management

Financial Review, Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. l982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

Modern Regulatory Finance, PUR Books, Reston, Va., 2022.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

“An Economic & Financial Profile of the Canadian Cablevision Industry,” Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

“Operational Risk Analysis: California Water Utilities,” Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique,” CRTC, 1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry," International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities,” Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Proxy Group for Arizona Public Service

	Company	Ticker
1	Alliant Energy	LNT
2	Amer. Elec. Power	AEP
3	Ameren Corp.	AEE
4	Avista Corp.	AVA
5	Black Hills	BKH
6	CenterPoint Energy	CNP
7	CMS Energy Corp.	CMS
8	Dominion Energy	D
9	Duke Energy	DUK
10	Edison Int'l	EIX
11	Entergy Corp.	ETR
12	Evergy Inc.	EVRG
13	Eversource Energy	ES
14	FirstEnergy Corp.	FE
15	IDACORP Inc.	IDA
16	MGE Energy	MGEE
17	NorthWestern Corp.	NWE
18	OGE Energy	OGE
19	Otter Tail Corp.	OTTR
20	Portland General	POR
21	Sempra Energy	SRE
22	Southern Co.	SO
23	WEC Energy Group	WEC
24	Xcel Energy Inc.	XEL

Vertically-Integrated Elec Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) Return on Equity
1	Alliant Energy	3.11	6.00	3.30	9.30	9.47
2	Amer. Elec. Power	3.52	6.50	3.75	10.25	10.45
3	Ameren Corp.	2.84	6.50	3.02	9.52	9.68
4	Avista Corp.	4.25	3.00	4.38	7.38	7.61
5	Black Hills	3.37	6.00	3.57	9.57	9.76
6	CenterPoint Energy	2.48	6.50	2.64	9.14	9.28
7	CMS Energy Corp.	2.95	6.50	3.14	9.64	9.81
8	Dominion Energy	3.57	14.00	4.07	18.07	18.28
9	Duke Energy	3.90	6.00	4.13	10.13	10.35
10	Edison Int'l	4.60	15.50	5.31	20.81	21.09
11	Entergy Corp.	3.87	4.00	4.02	8.02	8.24
12	Evergy Inc.	3.80	7.50	4.09	11.59	11.80
13	Eversource Energy	3.14	6.00	3.33	9.33	9.50
14	FirstEnergy Corp.	4.19	7.50	4.50	12.00	12.24
15	IDACORP Inc.	2.85	4.00	2.96	6.96	7.12
16	MGE Energy	2.06	6.06	2.18	8.24	8.36
17	NorthWestern Corp.	4.60	3.00	4.74	7.74	7.99
18	OGE Energy	4.38	6.50	4.66	11.16	11.41
19	Otter Tail Corp.	2.56	4.50	2.68	7.18	7.32
20	Portland General	3.69	4.50	3.86	8.36	8.56
21	Sempra Energy	3.05	7.50	3.28	10.78	10.95
22	Southern Co.	3.83	6.50	4.08	10.58	10.79
23	WEC Energy Group	3.13	6.00	3.32	9.32	9.49
24	Xcel Energy Inc.	2.97	6.00	3.15	9.15	9.31
26	**AVERAGE**	**3.45**	**6.50**	**3.67**	**10.18**	**10.37**

28 Notes:
29 Column 2, 3: Value Line Investment Analyzer 7/2022
30 Column 4 = Column 2 times (1 + Column 3/100)
31 Column 5 = Column 4 + Column 3
32 Column 6 = Column 4/0.95 + Column 3

Vertically-Integrated Elec Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) Return on Equity
1	Alliant Energy	3.11	6.00	3.30	9.30	9.47
2	Amer. Elec. Power	3.52	6.50	3.75	10.25	10.45
3	Ameren Corp.	2.84	6.50	3.02	9.52	9.68
4	Avista Corp.	4.25	3.00	4.38	7.38	7.61
5	Black Hills	3.37	6.00	3.57	9.57	9.76
6	CenterPoint Energy	2.48	6.50	2.64	9.14	9.28
7	CMS Energy Corp.	2.95	6.50	3.14	9.64	9.81
8	Dominion Energy	3.57	14.00	4.07	18.07	18.28
9	Duke Energy	3.90	6.00	4.13	10.13	10.35
10	Edison Int'l					
11	Entergy Corp.	3.87	4.00	4.02	8.02	8.24
12	Evergy Inc.	3.80	7.50	4.09	11.59	11.80
13	Eversource Energy	3.14	6.00	3.33	9.33	9.50
14	FirstEnergy Corp.	4.19	7.50	4.50	12.00	12.24
15	IDACORP Inc.	2.85	4.00	2.96	6.96	7.12
16	MGE Energy	2.06	6.06	2.18	8.24	8.36
17	NorthWestern Corp.	4.60	3.00	4.74	7.74	7.99
18	OGE Energy	4.38	6.50	4.66	11.16	11.41
19	Otter Tail Corp.	2.56	4.50	2.68	7.18	7.32
20	Portland General	3.69	4.50	3.86	8.36	8.56
21	Sempra Energy	3.05	7.50	3.28	10.78	10.95
22	Southern Co.	3.83	6.50	4.08	10.58	10.79
23	WEC Energy Group	3.13	6.00	3.32	9.32	9.49
24	Xcel Energy Inc.	2.97	6.00	3.15	9.15	9.31
26	**AVERAGE**	**3.40**	**6.11**	**3.60**	**9.71**	**9.90**

28 Notes:
29 Column 2, 3: Value Line Investment Analyzer 7/2022
30 Column 4 = Column 2 times (1 + Column 3/100)
31 Column 5 = Column 4 + Column 3
32 Column 6 = Column 4/0.95 + Column 3

Vertically Integrated Elec Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) Return on Equity
1	Alliant Energy	3.11	5.70	3.29	8.99	9.16
2	Amer. Elec. Power	3.52	6.20	3.74	9.94	10.13
3	Ameren Corp.	2.84	7.20	3.04	10.24	10.40
4	Avista Corp.	4.25	5.90	4.50	10.40	10.64
5	Black Hills	3.37	6.30	3.58	9.88	10.07
6	CenterPoint Energy	2.48	3.90	2.58	6.48	6.61
7	CMS Energy Corp.	2.95	8.10	3.19	11.29	11.46
8	Dominion Energy	3.57	6.30	3.79	10.09	10.29
9	Duke Energy	3.90	6.00	4.13	10.13	10.35
10	Edison Int'l	4.60	2.80	4.73	7.53	7.78
11	Entergy Corp.	3.87	6.70	4.13	10.83	11.05
12	Evergy Inc.	3.80	5.10	3.99	9.09	9.30
13	Eversource Energy	3.14	6.20	3.33	9.53	9.71
14	FirstEnergy Corp.	4.19	6.40	4.46	10.86	11.09
15	IDACORP Inc.	2.85	2.80	2.93	5.73	5.88
16	MGE Energy	2.06	4.20	2.15	6.35	6.46
17	NorthWestern Corp.	4.60	2.30	4.71	7.01	7.25
18	OGE Energy	4.38	3.50	4.53	8.03	8.27
19	Otter Tail Corp.	2.56	9.00	2.79	11.79	11.94
20	Portland General	3.69	4.40	3.85	8.25	8.46
21	Sempra Energy	3.05	5.80	3.23	9.03	9.20
22	Southern Co.	3.83	4.00	3.98	7.98	8.19
23	WEC Energy Group	3.13	6.10	3.32	9.42	9.60
24	Xcel Energy Inc.	2.97	6.40	3.16	9.56	9.73
26	**AVERAGE**	**3.45**	**5.47**	**3.63**	**9.10**	**9.29**

Notes:

29 Column 2: Value Line Investment Analyzer 7/2022
30 Column 3: Zacks Investment Research 7/22
31 Column 4 = Column 2 times (1 + Column 3/100)
32 Column 5 = Column 4 + Column 3
33 Otter Tail Corp growth rate unavailable from Zacks,
34 Yahoo Finance growth projection used instead.

Vertically-Integrated Elec Utilities Beta Estimates

Line No.	Company Name	(1) Beta
1	Alliant Energy	0.80
2	Amer. Elec. Power	0.75
3	Ameren Corp.	0.80
4	Avista Corp.	0.90
5	Black Hills	0.95
6	CenterPoint Energy	1.15
7	CMS Energy Corp.	0.75
8	Dominion Energy	0.80
9	Duke Energy	0.85
10	Edison Int'l	0.95
11	Entergy Corp.	0.90
12	Evergy Inc.	0.90
13	Eversource Energy	0.90
14	FirstEnergy Corp.	0.80
15	IDACORP Inc.	0.80
16	MGE Energy	0.70
17	NorthWestern Corp.	0.95
18	OGE Energy	1.00
19	Otter Tail Corp.	0.85
20	Portland General	0.85
21	Sempra Energy	0.95
22	Southern Co.	0.90
23	WEC Energy Group	0.80
24	Xcel Energy Inc.	0.80
26	**AVERAGE**	**0.87**

28 Source: Value Line Investment Analyzer 7/22

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
1	3M Company	MMM	6.50	4.48
2	Abbott Labs.	ABT	8.00	1.73
3	AbbVie Inc.	ABBV	4.50	3.81
4	Accenture Plc	ACN	12.50	1.46
5	Activision Blizzard	ATVI	12.50	0.65
6	Advance Auto Parts	AAP	16.00	3.11
7	Aflac Inc.	AFL	9.00	3.10
8	Agilent Technologies	A	11.50	0.70
9	Air Products & Chem.	APD	11.00	2.79
10	Albemarle Corp.	ALB	15.00	0.72
11	Alexandria Real Estate	ARE	10.00	3.19
12	Allegion plc	ALLE	10.50	1.61
13	Alliant Energy	LNT	6.00	3.11
14	Allstate Corp.	ALL	2.50	2.77
15	Altria Group	MO	5.50	8.50
16	Amcor plc	AMCR	14.00	3.84
17	Amer. Elec. Power	AEP	6.50	3.52
18	Amer. Express	AXP	10.00	1.39
19	Amer. Tower 'A'	AMT	9.00	2.39
20	Amer. Water Works	AWK	3.00	1.84
21	Ameren Corp.	AEE	6.50	2.84
22	Ameriprise Fin'l	AMP	12.50	2.06
23	AmerisourceBergen	ABC	8.50	1.32
24	AMETEK Inc.	AME	10.00	0.77
25	Amgen	AMGN	5.50	3.31
26	Amphenol Corp.	APH	12.50	1.16
27	Analog Devices	ADI	14.00	1.86
28	Aon plc	AON	7.50	0.81
29	Apple Inc.	AAPL	14.00	0.60
30	Applied Materials	AMAT	14.50	1.01
31	Archer Daniels Midl'd	ADM	13.00	2.14
32	Assurant Inc.	AIZ	14.00	1.81
33	AT&T Inc.	T	0.50	5.42
34	Atmos Energy	ATO	7.50	2.56
35	Automatic Data Proc.	ADP	9.00	2.09
36	AvalonBay Communities	AVB	6.50	3.38
37	Avery Dennison	AVY	12.00	1.77
38	Bank of America	BAC	9.50	2.57
39	Bank of New York Mellon	BK	6.50	3.43

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
40	Baxter Int'l Inc.	BAX	10.00	1.76
41	Becton Dickinson	BDX	5.50	1.51
42	Berkley (W.R.)	WRB	15.50	0.62
43	Best Buy Co.	BBY	7.00	4.50
44	Bio-Techne Corp.	TECH	17.50	0.37
45	BlackRock Inc.	BLK	10.00	3.19
46	BorgWarner	BWA	9.50	1.87
47	Broadridge Fin'l	BR	9.00	1.67
48	Brown & Brown	BRO	8.00	0.67
49	Brown-Forman 'B'	BF/B	14.00	1.07
50	C.H. Robinson	CHRW	8.00	2.16
51	Camden Property Trust	CPT	2.50	2.94
52	Campbell Soup	CPB	5.00	3.08
53	Cardinal Health	CAH	5.00	3.55
54	Caterpillar Inc.	CAT	10.00	2.66
55	Cboe Global Markets	CBOE	10.00	1.57
56	CDW Corp.	CDW	8.50	1.18
57	Celanese Corp.	CE	7.50	2.35
58	CenterPoint Energy	CNP	6.50	2.48
59	Chubb Ltd.	CB	11.00	1.79
60	Church & Dwight	CHD	6.00	1.12
61	Cigna Corp.	CI	9.50	1.68
62	Cincinnati Financial	CINF	7.00	2.48
63	Cintas Corp.	CTAS	13.50	0.96
64	Cisco Systems	CSCO	8.00	3.44
65	Citigroup Inc.	C	5.50	3.98
66	Citizens Fin'l Group	CFG	9.00	4.47
67	Clorox Co.	CLX	4.50	3.13
68	CME Group	CME	8.50	1.95
69	CMS Energy Corp.	CMS	6.50	2.95
70	Coca-Cola	KO	7.50	2.86
71	Cognizant Technology	CTSH	7.50	1.58
72	Colgate-Palmolive	CL	6.50	2.48
73	Comcast Corp.	CMCSA	9.50	2.58
74	Comerica Inc.	CMA	6.00	3.43
75	Conagra Brands	CAG	4.00	3.77
76	ConocoPhillips	COP	20.00	2.02
77	Consol. Edison	ED	4.50	3.50
78	Constellation Brands	STZ	5.00	1.31
79	Cooper Cos.	COO	18.50	0.02

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
80	Corning Inc.	GLW	17.50	3.13
81	Corteva Inc.	CTVA	16.50	1.11
82	Costco Wholesale	COST	10.50	0.68
83	Crown Castle Int'l	CCI	12.00	3.51
84	CSX Corp.	CSX	10.50	1.34
85	Cummins Inc.	CMI	8.50	3.05
86	CVS Health	CVS	6.00	2.31
87	Danaher Corp.	DHR	16.50	0.39
88	Darden Restaurants	DRI	19.50	3.97
89	Deere & Co.	DE	15.00	1.43
90	Dentsply Sirona	XRAY	10.00	1.38
91	Discover Fin'l Svcs.	DFS	8.50	2.18
92	Dollar General	DG	10.00	0.89
93	Dominion Energy	D	14.00	3.57
94	Domino's Pizza	DPZ	16.00	1.10
95	Dover Corp.	DOV	8.00	1.59
96	Dow Inc.	DOW	15.00	5.51
97	DTE Energy	DTE	4.50	3.01
98	Duke Energy	DUK	6.00	3.90
99	DuPont de Nemours	DD	10.00	2.38
100	Eastman Chemical	EMN	9.50	3.29
101	Eaton Corp. plc	ETN	12.00	2.42
102	eBay Inc.	EBAY	15.50	1.90
103	Ecolab Inc.	ECL	10.50	1.28
104	Edison Int'l	EIX	15.50	4.60
105	Electronic Arts	EA	11.50	0.61
106	Elevance Health	ELV	12.50	1.11
107	Emerson Electric	EMR	10.00	2.52
108	Entergy Corp.	ETR	4.00	3.87
109	Equifax Inc.	EFX	10.00	0.76
110	Equinix Inc.	EQIX	15.00	2.02
111	Everest Re Group Ltd.	RE	9.50	2.52
112	Evergy Inc.	EVRG	7.50	3.80
113	Eversource Energy	ES	6.00	3.14
114	Exelon Corp.	EXC	3.50	3.20
115	Expeditors Int'l	EXPD	6.50	1.31
116	Extra Space Storage	EXR	4.00	3.53
117	FactSet Research	FDS	10.00	0.88
118	Fastenal Co.	FAST	8.50	2.55
119	FedEx Corp.	FDX	10.50	2.02

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
120	Fifth Third Bancorp	FITB	11.00	3.71
121	First Republic Bank	FRC	11.00	0.68
122	FirstEnergy Corp.	FE	7.50	4.19
123	FMC Corp.	FMC	11.00	2.09
124	Fortive Corp.	FTV	11.50	0.49
125	Fortune Brands Home	FBHS	10.50	1.69
126	Fox Corp. 'A'	FOXA	11.00	1.38
127	Franklin Resources	BEN	4.00	4.56
128	Gallagher (Arthur J.)	AJG	16.00	1.22
129	Garmin Ltd.	GRMN	8.00	2.74
130	Gen'l Dynamics	GD	8.50	2.32
131	Gen'l Mills	GIS	3.50	2.94
132	Genuine Parts	GPC	9.00	2.51
133	Gilead Sciences	GILD	13.50	4.74
134	Global Payments	GPN	17.00	0.83
135	Globe Life Inc.	GL	8.50	0.83
136	Goldman Sachs	GS	5.00	3.11
137	Grainger (W.W.)	GWW	8.50	1.47
138	Hartford Fin'l Svcs.	HIG	8.50	2.43
139	Hasbro Inc.	HAS	9.00	3.44
140	HCA Healthcare	HCA	11.00	1.25
141	Healthpeak Properties	PEAK	17.00	4.55
142	Henry (Jack) & Assoc.	JKHY	9.00	1.00
143	Hershey Co.	HSY	7.00	1.69
144	Hewlett Packard Ent.	HPE	7.50	3.45
145	Home Depot	HD	9.00	2.58
146	Honeywell Int'l	HON	11.00	2.19
147	Hormel Foods	HRL	8.00	2.20
148	Horton D.R.	DHI	13.00	1.30
149	Howmet Aerospace	HWM	17.00	0.23
150	HP Inc.	HPQ	12.50	3.03
151	Humana Inc.	HUM	10.50	0.65
152	Hunt (J.B.)	JBHT	11.50	0.94
153	Huntington Bancshs.	HBAN	12.50	4.93
154	Huntington Ingalls	HII	10.00	2.25
155	IDEX Corp.	IEX	10.50	1.26
156	Illinois Tool Works	ITW	11.00	2.59
157	Int'l Business Mach.	IBM	3.00	5.10
158	Int'l Flavors & Frag.	IFF	7.50	2.64
159	Int'l Paper	IP	12.50	4.30

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
160	Intel Corp.	INTC	2.50	3.60
161	Intercontinental Exch.	ICE	6.50	1.54
162	Interpublic Group	IPG	10.00	4.00
163	Intuit Inc.	INTU	17.50	0.64
164	Invesco Ltd.	IVZ	11.50	4.54
165	Iron Mountain	IRM	11.00	5.35
166	Jacobs Engineering	J	12.00	0.71
167	Johnson & Johnson	JNJ	8.00	2.64
168	Johnson Ctrls. Int'l plc	JCI	12.50	2.84
169	JPMorgan Chase	JPM	7.00	3.75
170	Juniper Networks	JNPR	9.00	2.94
171	Kellogg	K	3.50	3.39
172	Keurig Dr Pepper	KDP	12.00	2.20
173	KeyCorp	KEY	9.00	4.30
174	Kimberly-Clark	KMB	5.50	3.53
175	Kimco Realty	KIM	8.50	3.92
176	Kinder Morgan Inc.	KMI	19.00	6.40
177	Kraft Heinz Co.	KHC	3.00	4.18
178	Kroger Co.	KR	6.50	2.20
179	L3Harris Technologies	LHX	18.50	1.99
180	Laboratory Corp.	LH	1.50	1.17
181	Lam Research	LRCX	17.00	1.29
182	Lamb Weston Holdings	LW	5.00	1.32
183	Lauder (Estee)	EL	14.00	1.02
184	Leidos Hldgs.	LDOS	9.00	1.44
185	Lennar Corp.	LEN	9.00	1.95
186	Lilly (Eli)	LLY	11.50	1.21
187	Lincoln Nat'l Corp.	LNC	11.50	3.69
188	Linde plc	LIN	12.00	1.65
189	LKQ Corp.	LKQ	11.00	1.88
190	Lockheed Martin	LMT	7.00	2.93
191	Loews Corp.	L	16.00	0.43
192	Lowe's Cos.	LOW	12.50	2.19
193	Lumen Technologies	LUMN	1.50	9.05
194	LyondellBasell Inds.	LYB	3.50	5.34
195	M&T Bank Corp.	MTB	8.00	3.02
196	MarketAxess Holdings	MKTX	10.50	1.04
197	Marsh & McLennan	MMC	11.50	1.53
198	Martin Marietta	MLM	5.50	0.75
199	Masco Corp.	MAS	8.50	2.11

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
200	MasterCard Inc.	MA	13.50	0.57
201	McCormick & Co.	MKC	6.00	1.82
202	McDonald's Corp.	MCD	10.50	2.23
203	McKesson Corp.	MCK	11.50	0.57
204	Medtronic plc	MDT	8.00	3.04
205	Merck & Co.	MRK	8.00	3.07
206	MetLife Inc.	MET	5.00	3.26
207	Microchip Technology	MCHP	10.00	1.67
208	Microsoft Corp.	MSFT	16.50	0.96
209	Mondelez Int'l	MDLZ	8.00	2.27
210	Moody's Corp.	MCO	8.00	0.96
211	Morgan Stanley	MS	9.00	3.78
212	Motorola Solutions	MSI	8.00	1.45
213	MSCI Inc.	MSCI	14.50	1.04
214	Nasdaq Inc.	NDAQ	6.00	1.42
215	NetApp Inc.	NTAP	8.00	2.98
216	Newmont Corp.	NEM	9.50	4.20
217	NextEra Energy	NEE	12.50	2.22
218	NiSource Inc.	NI	9.50	3.32
219	Nordson Corp.	NDSN	12.00	0.97
220	Norfolk Southern	NSC	10.50	2.08
221	Northern Trust Corp.	NTRS	8.00	2.88
222	Northrop Grumman	NOC	6.50	1.51
223	NortonLifeLock Inc.	NLOK	9.50	2.02
224	NXP Semi. NV	NXPI	12.00	1.91
225	Old Dominion Freight	ODFL	10.50	0.44
226	Omnicom Group	OMC	6.50	4.06
227	ONEOK Inc.	OKE	11.50	6.40
228	Oracle Corp.	ORCL	9.00	1.76
229	PACCAR Inc.	PCAR	9.50	3.39
230	Packaging Corp.	PKG	11.00	3.59
231	Paramount Global	PARA	7.50	3.69
232	Parker-Hannifin	PH	13.50	2.00
233	Paychex Inc.	PAYX	9.50	2.62
234	Pentair plc	PNR	12.50	1.72
235	PepsiCo Inc.	PEP	6.00	2.61
236	PerkinElmer Inc.	PKI	5.00	0.20
237	Pfizer Inc.	PFE	6.50	3.14
238	Philip Morris Int'l	PM	5.00	5.56
239	Pinnacle West Capital	PNW	0.50	4.96

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
240	PNC Financial Serv.	PNC	12.00	3.74
241	Pool Corp.	POOL	14.00	1.00
242	PPG Inds.	PPG	4.00	1.96
243	Price (T. Rowe) Group	TROW	8.00	4.09
244	Principal Fin'l Group	PFG	6.50	3.98
245	Procter & Gamble	PG	6.50	2.57
246	Progressive Corp.	PGR	6.50	0.35
247	Prologis	PLD	6.00	2.61
248	Prudential Fin'l	PRU	5.00	5.00
249	Public Serv. Enterprise	PEG	4.00	3.67
250	Public Storage	PSA	8.00	2.56
251	PulteGroup Inc.	PHM	11.00	1.42
252	PVH Corp.	PVH	13.50	0.23
253	Qualcomm Inc.	QCOM	19.00	1.97
254	Quanta Services	PWR	16.00	0.21
255	Quest Diagnostics	DGX	3.50	1.95
256	Ralph Lauren	RL	12.50	3.05
257	Raymond James Fin'l	RJF	14.50	1.42
258	Raytheon Technologies	RTX	7.00	2.31
259	Realty Income Corp.	O	6.00	4.34
260	Regency Centers Corp.	REG	12.50	3.95
261	Regions Financial	RF	10.00	3.74
262	Republic Services	RSG	12.50	1.42
263	ResMed Inc.	RMD	13.50	0.74
264	Robert Half Int'l	RHI	10.50	2.05
265	Rockwell Automation	ROK	9.50	2.08
266	Rollins Inc.	ROL	9.50	1.09
267	Roper Tech.	ROP	3.50	0.60
268	Ross Stores	ROST	13.50	1.56
269	S&P Global	SPGI	12.50	0.94
270	Schwab (Charles)	SCHW	9.00	1.27
271	Seagate Technology plc	STX	15.00	3.41
272	Sealed Air	SEE	10.00	1.38
273	Sempra Energy	SRE	7.50	3.05
274	Sherwin-Williams	SHW	11.50	1.00
275	Simon Property Group	SPG	3.00	6.76
276	Skyworks Solutions	SWKS	14.50	2.09
277	Smith (A.O.)	AOS	11.50	1.93
278	Smucker (J.M.)	SJM	4.00	3.15
279	Southern Co.	SO	6.50	3.83

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
280	Stanley Black & Decker	SWK	8.50	2.92
281	Starbucks Corp.	SBUX	16.50	2.45
282	State Street Corp.	STT	9.50	3.62
283	STERIS plc	STE	11.50	0.80
284	Stryker Corp.	SYK	8.50	1.40
285	Synchrony Financial	SYF	6.00	2.64
286	Sysco Corp.	SYY	16.50	2.22
287	Tapestry Inc.	TPR	15.00	2.95
288	Target Corp.	TGT	12.00	2.76
289	TE Connectivity	TEL	10.50	1.83
290	Teleflex Inc.	TFX	10.00	0.52
291	Teradyne Inc.	TER	9.00	0.43
292	Texas Instruments	TXN	9.00	2.78
293	Textron Inc.	TXT	10.50	0.12
294	Thermo Fisher Sci.	TMO	10.00	0.22
295	TJX Companies	TJX	17.00	1.87
296	Tractor Supply	TSCO	12.50	1.85
297	Travelers Cos.	TRV	6.50	2.35
298	Truist Fin'l	TFC	6.50	4.12
299	Tyson Foods 'A'	TSN	4.50	2.23
300	U.S. Bancorp	USB	6.00	4.29
301	UDR Inc.	UDR	10.50	3.43
302	Union Pacific	UNP	9.50	2.42
303	United Parcel Serv.	UPS	11.00	3.25
304	UnitedHealth Group	UNH	12.00	1.27
305	Universal Health `B'	UHS	9.00	0.74
306	V.F. Corp.	VFC	11.00	4.16
307	Valero Energy	VLO	12.50	3.58
308	Ventas Inc.	VTR	10.50	3.78
309	Verisk Analytics	VRSK	13.50	0.68
310	Verizon Communic.	VZ	3.00	5.29
311	VICI Properties	VICI	8.50	4.36
312	Visa Inc.	V	13.50	0.75
313	Vulcan Materials	VMC	8.50	1.03
314	Wabtec Corp.	WAB	9.50	0.69
315	Walgreens Boots	WBA	5.00	4.93
316	Walmart Inc.	WMT	7.50	1.71
317	Waste Management	WM	8.00	1.70
318	WEC Energy Group	WEC	6.00	3.13
319	Wells Fargo	WFC	11.50	2.45

PROSPECTIVE DCF MARKET RISK PREMIUM ANALYSIS
S&P 500 DIVIDEND-PAYING COMPANIES

	Company Name	Ticker	Proj EPS Gth	% Curr Yield
320	Welltower Inc.	WELL	3.50	3.14
321	West Pharmac. Svcs.	WST	17.00	0.23
322	WestRock Co.	WRK	20.00	2.43
323	Weyerhaeuser Co.	WY	8.00	2.04
324	Whirlpool Corp.	WHR	7.00	4.18
325	Williams Cos.	WMB	8.50	5.23
326	Willis Towers Wat. plc	WTW	8.00	1.64
327	Xcel Energy Inc.	XEL	6.00	2.97
328	Xylem Inc.	XYL	9.00	1.47
329	Yum! Brands	YUM	10.50	1.88
330	Zimmer Biomet Hldgs.	ZBH	5.50	0.88
331	Zions Bancorp.	ZION	8.00	2.96
332	Zoetis Inc.	ZTS	11.00	0.73
	AVERAGE		**9.61**	**2.41**

Source: Value Line Investment Analyzer 7/22

ELECTRIC UTILITIES CAPM AND ECAPM RESULTS

Line No.	Company Name	Risk-Free Rate (1)	Beta (2)	MRP (3)	CAPM Cost of Equity (4)	Flotation Cost (5)	CAPM ROE (6)	ECAPM Cost of Equity (7)	Flotation Cost (8)	ECAPM ROE (8)
1	Alliant Energy	3.70%	0.80	8.00%	10.10%	0.20%	10.30%	10.50%	0.20%	10.70%
2	Amer. Elec. Power	3.70%	0.75	8.00%	9.70%	0.20%	9.90%	10.20%	0.20%	10.40%
3	Ameren Corp.	3.70%	0.80	8.00%	10.10%	0.20%	10.30%	10.50%	0.20%	10.70%
4	Avista Corp.	3.70%	0.90	8.00%	10.90%	0.20%	11.10%	11.10%	0.20%	11.30%
5	Black Hills	3.70%	0.95	8.00%	11.30%	0.20%	11.50%	11.40%	0.20%	11.60%
6	CenterPoint Energy	3.70%	1.15	8.00%	12.90%	0.20%	13.10%	12.60%	0.20%	12.80%
7	CMS Energy Corp.	3.70%	0.75	8.00%	9.70%	0.20%	9.90%	10.20%	0.20%	10.40%
8	Dominion Energy	3.70%	0.80	8.00%	10.10%	0.20%	10.30%	10.50%	0.20%	10.70%
9	Duke Energy	3.70%	0.85	8.00%	10.50%	0.20%	10.70%	10.80%	0.20%	11.00%
10	Edison Int'l	3.70%	0.95	8.00%	11.30%	0.20%	11.50%	11.40%	0.20%	11.60%
11	Entergy Corp.	3.70%	0.90	8.00%	10.90%	0.20%	11.10%	11.10%	0.20%	11.30%
12	Evergy Inc.	3.70%	0.90	8.00%	10.90%	0.20%	11.10%	11.10%	0.20%	11.30%
13	Eversource Energy	3.70%	0.90	8.00%	10.90%	0.20%	11.10%	11.10%	0.20%	11.30%
14	FirstEnergy Corp.	3.70%	0.80	8.00%	10.10%	0.20%	10.30%	10.50%	0.20%	10.70%
15	IDACORP Inc.	3.70%	0.80	8.00%	10.10%	0.20%	10.30%	10.50%	0.20%	10.70%
16	MGE Energy	3.70%	0.70	8.00%	9.30%	0.20%	9.50%	9.90%	0.20%	10.10%
17	NorthWestern Corp.	3.70%	0.95	8.00%	11.30%	0.20%	11.50%	11.40%	0.20%	11.60%
18	OGE Energy	3.70%	1.00	8.00%	11.70%	0.20%	11.90%	11.70%	0.20%	11.90%
19	Otter Tail Corp.	3.70%	0.85	8.00%	10.50%	0.20%	10.70%	10.80%	0.20%	11.00%
20	Portland General	3.70%	0.85	8.00%	10.50%	0.20%	10.70%	10.80%	0.20%	11.00%
21	Sempra Energy	3.70%	0.95	8.00%	11.30%	0.20%	11.50%	11.40%	0.20%	11.60%
22	Southern Co.	3.70%	0.90	8.00%	10.90%	0.20%	11.10%	11.10%	0.20%	11.30%
23	WEC Energy Group	3.70%	0.80	8.00%	10.10%	0.20%	10.30%	10.50%	0.20%	10.70%
24	Xcel Energy Inc.	3.70%	0.80	8.00%	10.10%	0.20%	10.30%	10.50%	0.20%	10.70%
26	**AVERAGE**				**10.63%**		**10.83%**	**10.90%**		**11.10%**

ELECTRIC UTILITIES CAPM AND ECAPM RESULTS

Notes: Column (1): Risk-free rate
Column (2): see Exhibit RAM-5
Column (3): Market Risk Premium
Column (4): Column (1) + Column (2) x Column (3)
Column (5): Flotation cost allowance
Column (6): Column (4) + Column (5)
Column (7): Column (1) + 0.25 x Column (3) + 0.75 x Column (2) x Column (3)
Column (8): Column (7) + Column (5)

2021 Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	(2) Long-Term Government Income Component Bond Yield	(3) 20 year Maturity Bond Value	(4) Gain/Loss	(5) Interest	(6) Bond Total Return	(7) S&P Utility Index Return	(8) Utility Equity Risk Premium Over Bond Returns	(9) Utility Equity Risk Premium Over Bond Return Income Component
1	1931	4.07%	3.33%	1,000.00						
2	1932	3.15%	3.69%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-4.23%
3	1933	3.36%	3.12%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-24.99%
4	1934	2.93%	3.18%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.59%
5	1935	2.76%	2.81%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.82%
6	1936	2.56%	2.77%	1,031.15	31.15	27.60	5.88%	20.69%	14.81%	17.92%
7	1937	2.73%	2.66%	973.93	-26.07	25.60	-0.05%	-37.04%	-36.99%	-39.70%
8	1938	2.52%	2.64%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.81%
9	1939	2.26%	2.40%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	8.86%
10	1940	1.94%	2.23%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.38%
11	1941	2.04%	1.94%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.51%
12	1942	2.46%	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	2.44%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.63%
14	1944	2.46%	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	2.34%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	50.99%
16	1946	2.12%	2.04%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.78%
17	1947	2.43%	2.13%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.29%
18	1948	2.37%	2.40%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.61%
19	1949	2.09%	2.25%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.14%
20	1950	2.24%	2.12%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.13%
21	1951	2.69%	2.38%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	16.25%
22	1952	2.79%	2.66%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.59%
23	1953	2.74%	2.84%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.01%
24	1954	2.72%	2.79%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	21.93%

2021 Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	(2) Long-Term Government Income Component Bond Yield	(3) 20 year Maturity Bond Value	(4) Gain/Loss	(5) Interest	(6) Bond Total Return	(7) S&P Utility Index Return	(8) Utility Equity Risk Premium Over Bond Returns	(9) Utility Equity Risk Premium Over Bond Return Income Component
25	1955	2.95%	2.75%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.51%
26	1956	3.45%	2.99%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	2.07%
27	1957	3.23%	3.44%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	2.92%
28	1958	3.82%	3.27%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	37.43%
29	1959	4.47%	4.01%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.48%
30	1960	3.80%	4.26%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.00%
31	1961	4.15%	3.83%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.50%
32	1962	3.95%	4.00%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.44%
33	1963	4.17%	3.89%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.47%
34	1964	4.23%	4.15%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.76%
35	1965	4.50%	4.19%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.48%
36	1966	4.55%	4.49%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-8.97%
37	1967	5.56%	4.59%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-5.22%
38	1968	5.98%	5.50%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.82%
39	1969	6.87%	5.96%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-21.38%
40	1970	6.48%	6.74%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	9.82%
41	1971	5.97%	6.32%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.91%
42	1972	5.99%	5.87%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.28%
43	1973	7.26%	6.51%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-24.58%
44	1974	7.60%	7.27%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-28.82%
45	1975	8.05%	7.99%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.50%
46	1976	7.21%	7.89%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	23.92%
47	1977	8.03%	7.14%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	1.50%
48	1978	8.98%	7.90%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-11.61%
49	1979	10.12%	8.86%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	4.72%

2021 Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	(2) Long-Term Government Income Component Bond Yield	(3) 20 year Maturity Bond Value	(4) Gain/Loss	(5) Interest	(6) Bond Total Return	(7) S&P Utility Index Return	(8) Utility Equity Risk Premium Over Bond Returns	(9) Utility Equity Risk Premium Over Bond Return Income Component
50	1980	11.99%	9.97%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	5.11%
51	1981	13.34%	11.55%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	0.19%
52	1982	10.95%	13.50%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	13.02%
53	1983	11.97%	10.38%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	9.63%
54	1984	11.70%	11.74%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.30%
55	1985	9.56%	11.25%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	21.80%
56	1986	7.89%	8.98%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	19.55%
57	1987	9.20%	7.92%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-10.84%
58	1988	9.19%	8.97%	1,000.91	0.91	92.00	9.29%	18.27%	8.98%	9.30%
59	1989	8.16%	8.81%	1,100.73	100.73	91.90	19.26%	47.80%	28.54%	38.99%
60	1990	8.44%	8.19%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-10.76%
61	1991	7.30%	8.22%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	6.39%
62	1992	7.26%	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	7.17%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.24%
64	1994	7.99%	6.59%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-14.53%
65	1995	6.03%	7.60%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	34.55%
66	1996	6.73%	6.18%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.04%
67	1997	6.02%	6.64%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.05%
68	1998	5.42%	5.83%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	8.99%
69	1999	6.82%	5.57%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-14.42%
70	2000	5.58%	6.50%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	53.20%
71	2001	5.75%	5.53%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-35.94%
72	2002	4.84%	5.59%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-35.63%
73	2003	5.11%	4.80%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.31%
74	2004	4.84%	5.02%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.20%

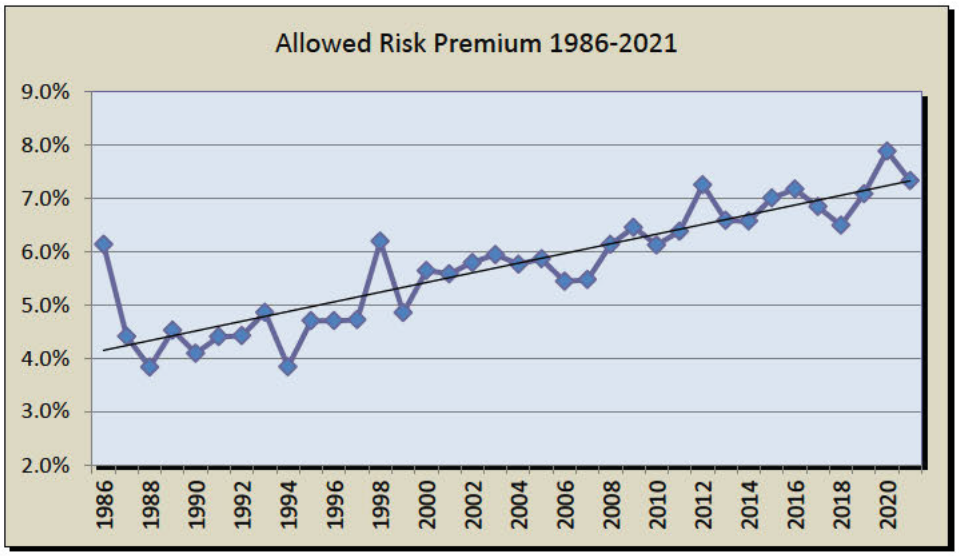
2021 Utility Industry Historical Risk Premium

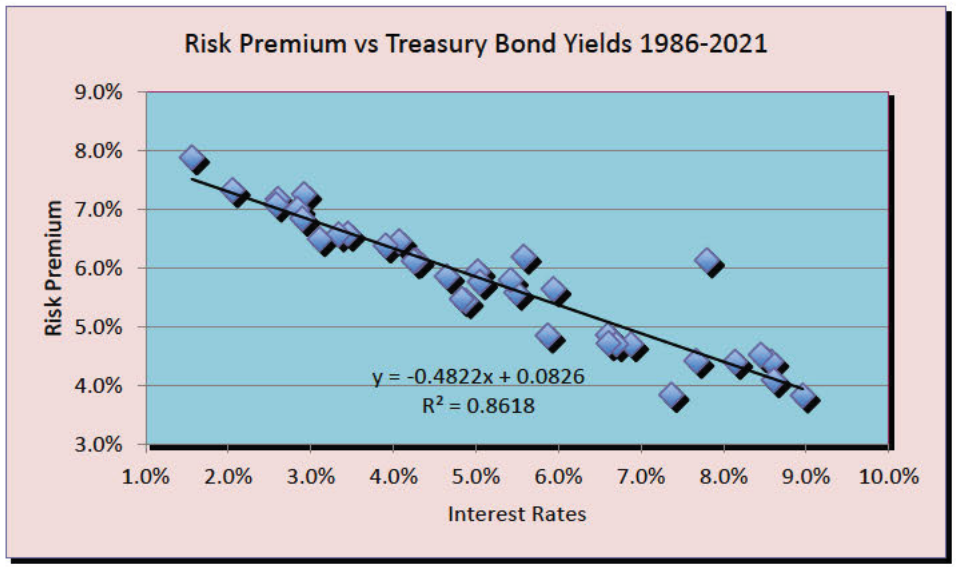
Line No.	Year	(1) Long-Term Government Bond Yield	(2) Long-Term Government Income Component Bond Yield	(3) 20 year Maturity Bond Value	(4) Gain/Loss	(5) Interest	(6) Bond Total Return	(7) S&P Utility Index Return	(8) Utility Equity Risk Premium Over Bond Returns	(9) Utility Equity Risk Premium Over Bond Return Income Component
75	2005	4.61%	4.69%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.10%
76	2006	4.91%	4.68%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.27%
77	2007	4.50%	4.86%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.50%
78	2008	3.03%	4.45%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%	-33.44%
79	2009	4.58%	3.47%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%	8.47%
80	2010	4.14%	4.25%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%	1.24%
81	2011	2.55%	3.82%	1,247.89	247.89	41.40	28.93%	19.88%	-9.05%	16.06%
82	2012	2.46%	2.46%	1,014.15	14.15	25.50	3.96%	1.29%	-2.67%	-1.17%
83	2013	3.78%	2.88%	815.92	-184.08	24.60	-15.95%	13.26%	29.21%	10.38%
84	2014	2.46%	3.41%	1,207.53	207.53	37.80	24.53%	28.61%	4.08%	25.20%
85	2015	2.68%	2.47%	966.11	-33.89	24.60	-0.93%	1.38%	2.31%	-1.09%
86	2016	2.72%	2.30%	993.86	-6.14	26.80	2.07%	16.27%	14.20%	13.97%
87	2017	2.54%	2.67%	1,028.09	28.09	27.20	5.53%	12.11%	6.58%	9.44%
88	2018	2.84%	2.82%	954.46	-45.54	25.40	-2.01%	4.11%	6.12%	1.29%
89	2019	2.25%	2.55%	1,094.60	94.60	28.40	12.30%	31.48%	19.18%	28.93%
90	2020	1.37%	1.53%	1,153.49	153.49	22.50	17.60%	0.05%	-17.55%	-1.48%
91	2021	1.88%	1.73%	915.31	-84.69	13.70	-7.10%	4.20%	11.30%	2.47%
93	**Mean**								**5.53%**	**6.25%**

95 Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.
96 Long-Term Government Bond yield data from Duff & Phelps 2022 Valuation Yearbook Appendices A7 and A9

ALLOWED RISK PREMIUM ANALYSIS

Line	Date	Treasury Bond Yield[1] (1)	Authorized Electric Returns[2] (2)	Indicated Risk Premium (3)
1	1986	7.80%	13.93%	6.1%
2	1987	8.58%	12.99%	4.4%
3	1988	8.96%	12.79%	3.8%
4	1989	8.45%	12.97%	4.5%
5	1990	8.61%	12.70%	4.1%
6	1991	8.14%	12.54%	4.4%
7	1992	7.67%	12.09%	4.4%
8	1993	6.60%	11.46%	4.9%
9	1994	7.37%	11.21%	3.8%
10	1995	6.88%	11.58%	4.7%
11	1996	6.70%	11.40%	4.7%
12	1997	6.61%	11.33%	4.7%
13	1998	5.58%	11.77%	6.2%
14	1999	5.87%	10.72%	4.9%
15	2000	5.94%	11.58%	5.6%
16	2001	5.49%	11.07%	5.6%
17	2002	5.42%	11.21%	5.8%
18	2003	5.02%	10.96%	5.9%
19	2004	5.05%	10.81%	5.8%
20	2005	4.65%	10.51%	5.9%
21	2006	4.88%	10.32%	5.4%
22	2007	4.83%	10.30%	5.5%
23	2008	4.28%	10.41%	6.1%
24	2009	4.07%	10.52%	6.5%
25	2010	4.25%	10.37%	6.1%
26	2011	3.91%	10.29%	6.4%
27	2012	2.92%	10.17%	7.3%
28	2013	3.45%	10.03%	6.6%
29	2014	3.34%	9.91%	6.6%





ALLOWED RISK PREMIUM ANALYSIS

Line	Date	Treasury Bond Yield[1]	Authorized Electric Returns[2]	Indicated Risk Premium
30	2015	2.84%	9.84%	7.0%
31	2016	2.60%	9.77%	7.2%
32	2017	2.90%	9.74%	6.8%
33	2018	3.11%	9.60%	6.5%
34	2019	2.58%	9.66%	7.1%
35	2020	1.56%	9.44%	7.9%
36	2021	2.06%	9.38%	7.3%
	Average	**5.25%**	**10.98%**	**5.73%**

IF YIELD =	3.70%
THEN RP =	6.48%
Ke =	10.18%

Sources:

1 Fed Reserve Board of Governors H.15 Release, 30-Yr Treasury rate

2 S&P Global Intelligence (Regulatory Research Associates)

Major Rate Case Decisions 1986-2021

CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

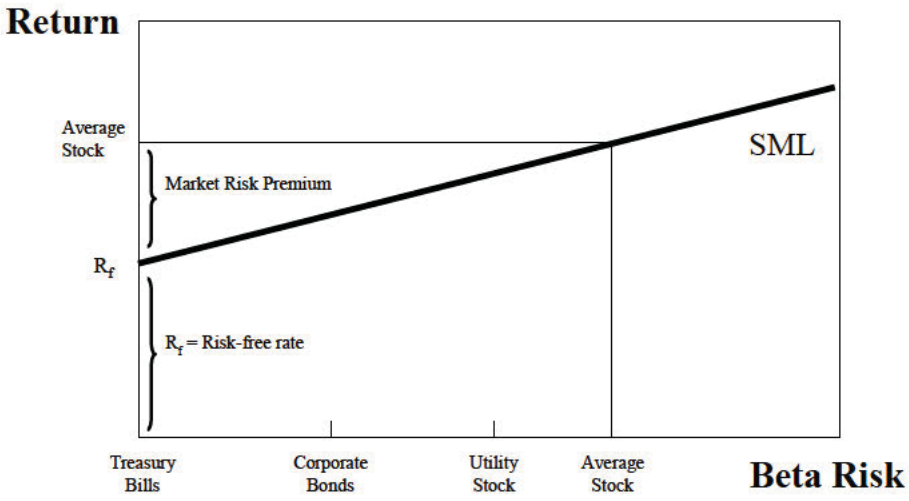
$$K = R_F + \beta(R_M - R_F) \quad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, **β,** and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

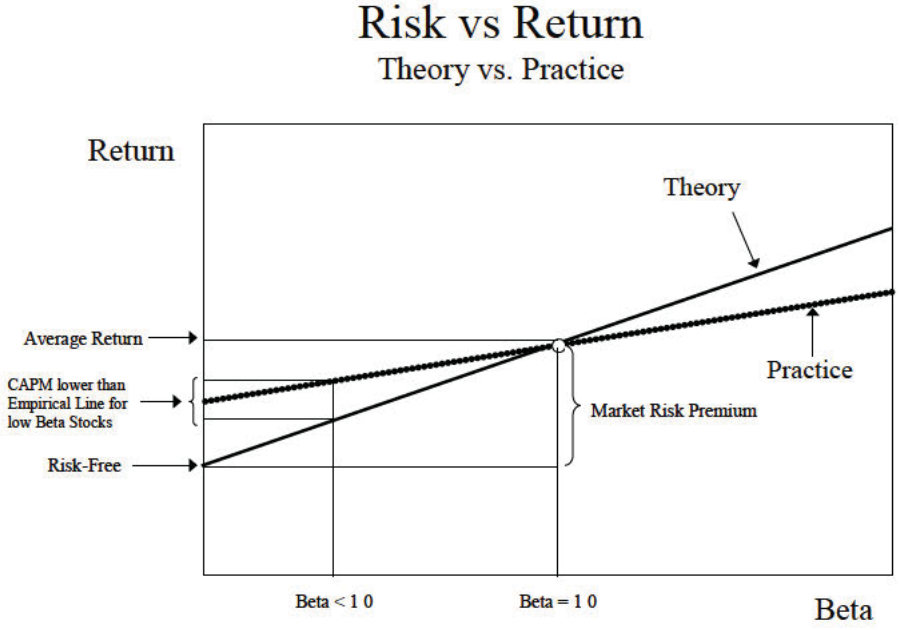
$$K = R_F + \beta \times MRP \quad (2)$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

CAPM and Risk - Return
in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [The New Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 2006].



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta (MRP - \alpha) \quad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \quad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

In order to rectify the CAPM's basic shortcomings, Litzenberger, Ramaswamy, and Sosin (1980) not only summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems[1]. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios, are related to their corresponding betas by statistical regression techniques;

[1] Litzenberger, R.H., Ramaswamy, K., and Sosin, H. "On the CAPM Approach to the Estimation of a Public Utility's Cost of Equity Capital." *Journal of Finance,* May 1980, 369-383.

that is, Equation (3) is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their results demonstrate how the standard CAPM underestimates the cost of equity of public utilities because of utilities' high dividend yield and return skewness.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied**
Black (1993)	-3.6% to 3.6%	1931-1991
Black, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien (2003)	2.0%	1983-1998

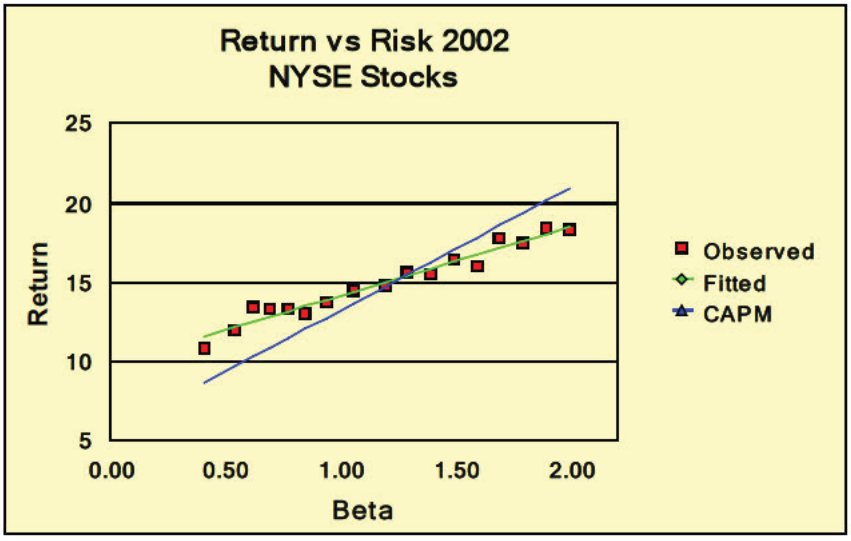
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

$$K = .0829 + .0520 \beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium (R_M - R_F) = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

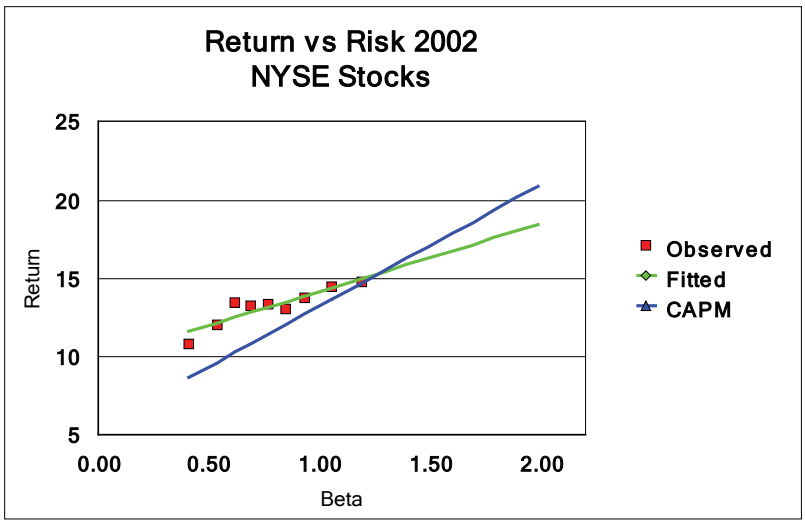
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[2]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:

[2] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

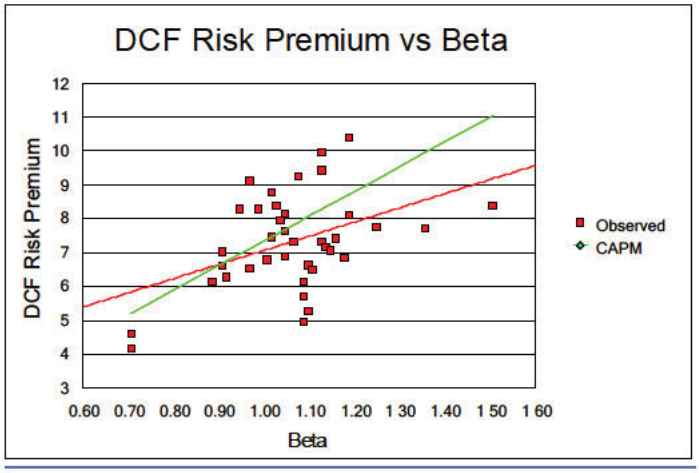


Table A-1 Risk Premium and Beta Estimates by Industry

	Industry	DCF Risk Premium	Raw Industry Beta	Adjusted Industry Beta
	(1)	(2)	(3)	(4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51

18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15
32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta (MRP - \alpha) \quad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \quad (6)$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[3]. An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$K = R_F + \alpha + \beta (MRP - \alpha)$$
$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$
$$= 11\%$$

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the 'a" coefficient is 0.25, and the ECAPM becomes[4]:

[3] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

[4] Recall that alpha equals 'a' times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is

$$K = R_F + 0.25\ MRP + 0.75\ \beta\ MRP$$

Returning to the numerical example, the utility's cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[5].

2 percent, then a = 0.25

[5] In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\ \beta$$

The value of a that best explained the observed relationship was 0.25.

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FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the

prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

In a 2014 study filed before the State of Texas Comptroller of Public Accounts Property Tax Division by Bwembya Chikolwa and Rick Parker, "Capitalization Rate Study Gas And Liquid Pipeline Industry," Appendix C, the average direct flotation cost on more than 100 common stock issuances in the gas and liquid pipeline industry was 3.22% without the market pressure effect.

In a recent comprehensive study, Tegarden Associates (2020) estimate the flotation costs for both debt and common equity issues for several hundred utilities, and find results consistent with the finding of earlier studies, namely that the direct flotation associated with utility common stock issues is 3% without the market pressure effect[1].

FLOTATION COSTS: RAISING EXTERNAL CAPITAL

(Percent of Total Capital Raised)

[1] Tegarden & Associates, "Appraisal of the Operating Properties of PacifiCorp," Utah State Tax Commission, Appeal No. 20-1050, Jan. 2020.

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9. 99	13.28%	4.39%
10 - 19. 99	8.72	2.76
20 - 39. 99	6.93	2.42
40 - 59. 99	5.87	1.32
60 - 79. 99	5.18	2.34
80 - 99. 99	4.73	2.16
100 - 199. 99	4.22	2.31
200 - 499. 99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. It is therefore reasonable to assume a 5% total flotation cost allowance in cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1-f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if

investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%

EQUITY RETURN = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	**5.00%**		**5.00%**	**5.00%**	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	**4.53%**		**4.53%**	**4.53%**	

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE A-1
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTIONAL
ADJUSTED TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	Electric Original Cost	Electric RCND	Electric Fair Value	Line No.
1.	Rate Base	$ 10,515,877 (a)	$ 22,653,031 (a)	$ 16,584,454	1.
2.	Operating Income	237,851 (b)	237,851 (b)	237,851 (b)	2.
3.	Current Rate of Return	2.26%	1.05%	1.43%	3.
4.	Required Operating Income	753,988	753,988	753,988	4.
5.	Required Rate of Return on OCRB	7.17% (d)	3.33% *	4 55% *	5.
6.	Operating Income Deficiency on OCRB	516,137	516,137	516,137	6.
7.	Gross Revenue Conversion Factor	1 3359 (c)	1 3359 (c)	1.3359 (c)	7.
8.	Increase in Base Revenue Requirements Based on OCRB	$ 689,492 **	$ 689,492 **	$ 689,492 **	8.
9.	After Tax Return on Fair Value Increment			82,780	9.
10.	Requested Increase in Base Revenue Requirements			$ 772,272	10.
11.	Required Rate of Return with Fair Value Increment			4 92%	11.

	Customer Classifica ion	Projected Revenue Increase Due to Base Rates	Base Rate % Increase (e)	Adjustor Transfer Net Bill Impact % Increase (e)	Day One Net Bill Impact % Increase (e)	
12.	Residential	$ 414,702	22.79%	19.10%	13.62%	12.
13.	General Service	344,238	22.96%	20.39%	13.62%	13.
14.	Irriga ion and Water Pumping	8,370	27.59%	21.55%	13.62%	14.
15.	Outdoor Lighting	3,599	18.65%	17.69%	13.62%	15.
16.	Dusk-to-Dawn	1,363	15.51%	15.12%	13.62%	16.
17.	Total	772,272 (e)	22.87%	19.68%	13.62%	17.
18.	Total Sales to Ultimate Retail Customers under Present Rates	$ 3,376,812 (e)				18.

Notes:

* The Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.

** Does not include the fair value increment reflected on Line 9.

Supporting Schedules:
(a) B-1
(b) C-1, page 2 of 2
(c) C-3
(d) D-1
(e) H-1

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENTS SCHEDULE A-2
SUMMARY RESULTS OF OPERATIONS
TOTAL COMPANY
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars, except per share amounts)

Line No.	Description	Prior Years		Test Year		Projected Years					Line No.
		Year Ended 12/31/2020 (a)	Year Ended 12/31/2021 (a)	Actual 6/30/2022 (a)	Adjusted 6/30/2022 (b)	Present Rates 12/31/2022 (c)	Present Rates 12/31/2023 (c)	Present Rates 12/31/2024 (c)	Proposed Rates 12/31/2023 (c) *	Proposed Rates 12/31/2024 (c)	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(H)	
1.	Gross Revenues	$ 3,591,984	$ 3,823,903	$ 3,981,825	$ 3,751,031	$ 4,117,798	$ 4,396,264	$ 4,635,062	$ 4,424,426	$ 5,124,336	1.
2.	Revenue Deductions & Operating Expenses	2,833,179	3,035,236	3,237,207	3,354,572	3,511,031	3,714,104	3,962,247	3,723,678	4,131,260	2.
3.	Operating Income	758,805	788,667	744,618	396,458	606,768	682,160	672,814	700,748	993,076	3.
4.	Other Income and (Deductions)	24,411	65,617	56,158	56,158	121,089	80,776	78,101	81,318	77,985	4.
5.	Interest Expense	215,188	222,005	229,362	229,362	248,622	293,126	315,325	295,442	303,686	5.
6.	Net Income	$ 568,028	$ 632,279	$ 571,414	$ 223,254	$ 479,234	$ 469,810	$ 435,590	$ 486,624	$ 767,375	6.
7.	Earnings Per Average Common Share *	$ 7 97	$ 8.87	$ 8.02	$ 3.13	N/A	N/A	N/A	N/A	N/A	7.
8.	Dividends Per Common Share *	$ 5 09	$ 5.32	$ 5.39	$ 5 39	N/A	N/A	N/A	N/A	N/A	8.
9.	Payout Ratio *	63 9%	59.9%	67.2%	172 0%	N/A	N/A	N/A	N/A	N/A	9.
10.	Total Company Return on Average Invested Capital	6 6%	6.7%	6.1%	3.4%	5.4%	5.3%	5.0%	5.5%	7.2%	10.
11.	Total Company Return on Year End Capital	6 5%	6.5%	5.9%	3.4%	5 2%	5.2%	4.9%	5.4%	7.0%	11.
12.	Total Company Return on Average Common Equity	9.4%	9.8%	8.7%	3 3%	7.1%	6.7%	5.9%	7.0%	10.2%	12.
13.	Total Company Return on Year End Common Equity	9.1%	9.5%	8.4%	3 3%	7 0%	6.6%	5.7%	6.8%	9.7%	13.
14.	ACC Jurisdictional Return on Year End Common Equity	8 9%	9 5%	8.2%	0.8%	6 2%	5.9%	4.9%	6.2%	9.7%	14.
15.	Times Bond Interest Earned - Before Income Taxes	4.1	4.4	4 0	2.1	3.3	2.9	2 6	2 9	4.1	15.
16.	Times Total Interest & Preferred Dividends Earned - After Income Taxes	3.6	3.8	3 5	2.0	2.9	2.6	2.4	2 6	3 5	16.

Notes
* Proposed Rates for year-end 12/31/2023 includes one month of proposed rates, as assumed effective date is 12/1/2023.

Supporting Schedules:
(a) E-2
(b) C-1
(c) F-1

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE A-3
SUMMARY OF CAPITAL STRUCTURE
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	Prior Years (a) Year Ended 12/31/2020 (A)	Prior Years (a) Year Ended 12/31/2021 (B)	Actual Test Year (a) Ended 6/30/2022 (C)	Projected Years (b) Present Rates Year Ended 12/31/2022 (D)	Present Rates Year Ended 12/31/2023 (E)	Present Rates Year Ended 12/31/2024 (F)	Proposed Rates Year Ended 12/31/2023 *** (G)	Proposed Rates Year Ended 12/31/2024 (H)	Line No.
1.	Short-Term Debt *	$ -	$ 278,700	$ 515,000	$ -	$ -	$ -	$ -	$ -	1.
2.	Long-Term Debt (with Cur Maturities) **	5,865,975	6,315,975	6,315,975	6,943,975	7,443,975	7,693,975	7,493,975	7,343,975	2.
3.	TOTAL DEBT	5,865,975	6,594,675	6,830,975	6,943,975	7,443,975	7,693,975	7,493,975	7,343,975	3.
4.	Preferred Stock	-	-	-	-	-	-	-	-	4.
5.	Common Equity	6,225,895	6,635,213	6,786,040	6,912,266	7,134,653	7,638,505	7,151,486	7,937,270	5.
6.	Total Capital	$ 12,091,870	$ 13,229,888	$ 13,617,015	$ 13,856,241	$ 14,578,628	$ 15,332,480	$ 14,645,461	$ 15,281,245	6.
	Capitalization Ratios:									
7.	Short-Term Debt *	0.00%	2.11%	3.78%	0 00%	0.00%	0.00%	0.00%	0.00%	7.
8.	Long-Term Debt	48.51%	47.74%	46 38%	50.11%	51.06%	50.18%	51.17%	48.06%	8.
9.	TOTAL DEBT	48.51%	49.85%	50.16%	50.11%	51.06%	50.18%	51.17%	48.06%	9.
10.	Preferred Stock	0.00%	0.00%	0 00%	0 00%	0.00%	0.00%	0.00%	0.00%	10.
11.	Common Equity	51.49%	50.15%	49 84%	49 89%	48.94%	49.82%	48.83%	51.94%	11.
		100.00%	100.00%	100 00%	100 00%	100.00%	100.00%	100.00%	100.00%	
12.	Weighted Cost of Short-Term Debt *	0.00%	0.00%	0 07%	0 00%	0.00%	0.00%	0.00%	0.00%	12.
13.	Weighted Cost of Long-Term Debt	1.93%	1.84%	1.79%	1 96%	2.09%	2.12%	2.10%	2.06%	13.
14.	Weighted Cost of Senior Capital	0.00%	0.00%	0 00%	0 00%	0.00%	0.00%	0.00%	0.00%	14.

Notes
* Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress and is therefore recoverable through AFUDC provisions and excluded from the cost of capital calculation. For the unadjusted Test Year ended 6/30/2022 there was $515,000 of short-term debt.
** Debt balances exclude unamortized discounts/premiums/debt issuance costs and the Palo Verde capital lease obligation.
*** Proposed Rates for year-end 12/31/2023 includes one month of proposed rates, as assumed effective date is 12/1/2023.

Supporting Schedules:
(a) E-1
(b) D-1

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE A-4
CONSTRUCTION EXPENDITURES, NET PLANT PLACED IN SERVICE AND GROSS UTILITY PLANT IN SERVICE
TOTAL COMPANY
PRIOR YEARS, CURRENT YEAR AND PROJECTED YEARS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Year	Construction* Expenditures *(A)*	Net Plant Placed In Service *(B)*	Gross Utility Plant in Service *(C)*	*Line No.*
1.	Year Ended 2020	$ 1,258,729	$ 1,045,741	$ 21,549,365	*1.*
2.	Year Ended 2021	1,495,016	882,569	22,431,934 (b)	*2.*
3.	6 Months Ended June 30, 2022	726,951 (a)	511,315	22,943,249 (b)	*3.*
4.	Projected Year - Year Ended 12/31/2022	1,519,269 (a)	771,596	23,714,845	*4.*
5.	Projected Year - Year Ended 12/31/2023	1,521,061 (a)	1,756,821	25,471,665	*5.*
6.	Projected Year - Year Ended 12/31/2024	1,645,982 (a)	1,074,298	26,545,963	*6.*

Notes:
* Includes nuclear fuel and all construction expenditures reflected on accrual basis

Supporting Schedules:
(a) F-3
(b) E-5

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE A-5
SUMMARY OF CHANGES IN FINANCIAL POSITION
TOTAL COMPANY
PRIOR YEARS, CURRENT YEAR AND PROJECTED YEARS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	Prior Years (a) Year Ended 12/31/2020 (A)	Prior Years (a) Year Ended 12/31/2021 (B)	Actual Test Year (a) Year Ended 6/30/2022 (C)	Projected Years (b) Present Rates Year Ended 12/31/2022 (b) (D)	Projected Years (b) Present Rates Year Ended 12/31/2023 (b) (E)	Projected Years (b) Present Rates Year Ended 12/31/2024 (b) (F)	Projected Years (b) Proposed Rates Year Ended 12/31/2023 (b) ** (G)	Projected Years (b) Proposed Rates Year Ended 12/31/2024 (b) (H)	Line No.
	Sources / Use of Funds:									
1.	Operations	$ 908,162	$ 845,263	$ 1,132,713	$ 1,286,840	$ 1,414,550	$ 1,484,689	$ 1,435,957	$ 1,831,149	1.
2.	Outside Financing	427,072	499,199	385,499	308,886	163,539	209,856	142,132	(136,603)	2.
3.	Total Funds Provided	$ 1,335,234	$ 1,344,462	$ 1,518,212	$ 1,595,726	$ 1,578,088	$ 1,694,545	$ 1,578,088	$ 1,694,545	3.
	Application of Funds:									
4.	Capital Expenditures *	$ 1,220,775	$ 1,421,047	$ 1,475,572	$ 1,557,752	$ 1,525,093	$ 1,643,201	$ 1,525,093	$ 1,643,201	4.
5.	Other	67,318	(28,649)	26,812	47,348	52,996	51,344	52,996	51,344	5.
6.	Total Funds Applied	$ 1,288,093	$ 1,392,398	$ 1,502,384	$ 1,605,100	$ 1,578,089	$ 1,694,545	$ 1,578,089	$ 1,694,545	6.

Notes:
* Capital expenditures are shown net of contributions in aid of construction and are reflected on a cash basis.
** Proposed Rates for year-end 12/31/2023 includes one month of proposed rates, as assumed effective date is 12/1/2023.

Supporting Schedules:
(a) E-3
(b) F-2

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENTS SCHEDULE B-1
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	Original Cost — Total Company: Unadjusted Test Year Ended 6/30/2022 (a) (A)	Pro Forma (a) (B)	Adjusted Test Year Ended 6/30/2022 (a) (C)	Original Cost — ACC: Unadjusted Test Year Ended 6/30/2022 (a) (D)	Pro Forma (a) (E)	Adjusted Test Year Ended 6/30/2022 (a) (F)	Line No.
1.	Gross utility plant in service	$ 23,391,974	$ 1,198,620	$ 24,590,594	$ 19,763,613	$ 1,172,010	$ 20,935,623	1.
2.	Less: Accumulated depreciation & amortization (b)	8,525,605	611,123	9,136,728	7,428,088	596,533	8,024,621	2.
3.	Net utility plant in service	14,866,369	587,498	15,453,867	12,335,525	575,477	12,911,002	3.
	Deductions:							
4.	Deferred income taxes	2,354,272	25,048	2,379,320	2,352,811	25,896	2,378,707	4.
5.	Deferred investment tax credits (b)	184,032	-	184,032	181,609	-	181,609	5.
6.	Customer advances (b)	336,198	-	336,198	305,254	-	305,254	6.
7.	Customer deposits	40,063	-	40,063	40,063	-	40,063	7.
8.	Liabilities for pension benefits	89,240	-	89,240	88,065	-	88,065	8.
9.	Liability for asset retirements (b)	784,472	-	784,472	774,145	-	774,145	9.
10.	Other deferred credits	21,110	-	21,110	20,832	-	20,832	10.
11.	Coal mine reclamation (b)	176,936	-	176,936	174,607	-	174,607	11.
12.	Unrecognized tax benefits (b)	37,662	-	37,662	37,166	-	37,166	12.
13.	Operating lease liabilities (b)	843,713	-	843,713	647,798	-	647,798	13.
14.	Regulatory liabilities	2,006,789	-	2,006,789	2,107,798	-	2,107,798	14.
15.	Total deductions	6,874,487	25,048	6,899,535	6,730,148	25,896	6,756,044	15.
	Additions:							
16.	Regulatory assets	1,182,539	30,916	1,213,455	1,242,061	28,959	1,271,020	16.
17.	Other deferred debits	30,089	-	30,089	28,369	-	28,369	17.
18.	Nuclear Decommissioning trust (b)	1,076,088	-	1,076,088	1,074,797	-	1,074,797	18.
19.	Other special use funds (b)	346,406	-	346,406	345,990	-	345,990	19.
20.	Assets for pension and other postretirement benefits (b)	568,515	-	568,515	518,467	-	518,467	20.
21.	Operating lease right-of-use assets (b)	866,182	-	866,182	665,050	-	665,050	21.
22.	Allowance for working capital (c)	506,483	(15,189)	491,294	471,078	(13,852)	457,226	22.
23.	Total additions	4,576,302	15,727	4,592,029	4,345,812	15,107	4,360,919	23.
24.	Total rate base	$ 12,568,184	$ 578,176	$ 13,146,360	$ 9,951,189	$ 564,688	$ 10,515,877 (d)	24.

Supporting Schedules:
(a) B-2
(b) E-1
(c) B-5

Recap Schedules:
(d) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-1
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	RCND Total Company: Unadjusted Test Year Ended 6/30/2022 (a) (d) (A)	RCND Total Company: Pro Forma (a) (B)	RCND Total Company: Adjusted Test Year Ended 6/30/2022 (a) (C)	RCND ACC: Unadjusted Test Year Ended 6/30/2022 (a) (d) (D)	RCND ACC: Pro Forma (a) (E)	RCND ACC: Adjusted Test Year Ended 6/30/20221 (a) (F)	Line No.
1.	Gross utility plant in service	$ 46,215,482	$ 1,198,620	$ 47,414,102	$ 39,046,936	$ 1,172,010	$ 40,218,946	1.
2.	Less: Accumulated depreciation & amortization	16,727,637	611,123	17,338,760	14,574,257	596,533	15,170,790	2.
3.	Net utility plant in service	29,487,845	587,498	30,075,343	24,472,679	575,477	25,048,156	3.
	Deductions:							
4.	Deferred income taxes	2,354,272	25,048	2,379,320	2,352,811	25,896	2,378,707	4.
5.	Deferred investment tax credits (b)	184,032	-	184,032	181,609	-	181,609	5.
6.	Customer advances (b)	336,198	-	336,198	305,254	-	305,254	6.
7.	Customer deposits	40,063	-	40,063	40,063	-	40,063	7.
8.	Liabilities for pension benefits	89,240	-	89,240	88,065	-	88,065	8.
9.	Liability for asset retirements (b)	784,472	-	784,472	774,145	-	774,145	9.
10.	Other deferred credits	21,110	-	21,110	20,832	-	20,832	10.
11.	Coal mine reclamation (b)	176,936	-	176,936	174,607	-	174,607	11.
12.	Unrecognized tax benefits (b)	37,662	-	37,662	37,166	-	37,166	12.
13.	Operating lease liabilities (b)	843,713	-	843,713	647,798	-	647,798	13.
14.	Regulatory liabilities	2,006,789	-	2,006,789	2,107,798	-	2,107,798	14.
15.	Total deductions	6,874,487	25,048	6,899,535	6,730,148	25,896	6,756,044	15.
	Additions:							
16.	Regulatory assets	1,182,539	30,916	1,213,455	1,242,061	28,959	1,271,020	16.
17.	Other deferred debits	30,089	-	30,089	28,369	-	28,369	17.
18.	Nuclear Decommissioning trust (b)	1,076,088	-	1,076,088	1,074,797	-	1,074,797	18.
19.	Other special use funds (b)	346,406	-	346,406	345,990	-	345,990	19.
20.	Assets for other postretirement benefits (b)	568,515	-	568,515	518,467	-	518,467	20.
21.	Operating lease right-of-use assets (b)	866,182	-	866,182	665,050	-	665,050	21.
22.	Allowance for working capital (c)	506,483	(15,189)	491,294	471,078	(13,852)	457,226	22.
23.	Total additions	4,576,302	15,727	4,592,029	4,345,812	15,107	4,360,919	23.
24.	Total rate base	$ 27,189,660	$ 578,176 (d)	$ 27,767,836 (d)	$ 22,088,343	$ 564,688 (d)	$ 22,653,031 (d)(e)	24.

Supporting Schedules:
(a) B-3
(b) E-1
(c) B-5
(d) B-4a

Recap Schedules:
(e) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(1) Actual at End of Test Year Ended 6/30/22 (a) Total Co. (A)	(1) Actual at End of Test Year Ended 6/30/22 (a) ACC (B)	(2) Other Generation Post-Test Year Plant Additions Total Co. (C)	(2) Other Generation Post-Test Year Plant Additions ACC (D)	(3) Nuclear Generation Post-Test Year Plant Additions Total Co. (E)	(3) Nuclear Generation Post-Test Year Plant Additions ACC (F)
1.	Gross Utility Plant in Service	$ 23,391,974	$ 19,763,613	$ 300,928	$ 300,567	$ 63,405	$ 63,329
2.	Less: Accumulated Depreciation & Amort.	8,525,605	7,428,088	222,290	222,023	14,308	14,291
3.	Net Utility Plant in Service	14,866,369	12,335,525	78,638	78,544	49,097	49,038
4.	Less: Total Deductions	6,874,487	6,730,150	(14,269)	(14,251)	2,907	2,904
5.	Total Additions	4,576,302	4,345,811	-	-	-	-
6.	Total Rate Base	$ 12,568,184	$ 9,951,185	$ 92,907	$ 92,795	$ 46,190	$ 46,134

PRO FORMA WITNESS:

TETLOW

TETLOW

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]

1. Jurisdictional
2. Assigned to Production - Demand
(DEMPROD1; Schedule G-7 line 17)

1. Jurisdictional
2. Assigned to Production - Demand
(DEMPROD1; Schedule G-7 line 17)

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1.

(2) Adjustment to Test Year rate base to include post-Test Year plant additions for Other Generation with an estimated in-service date prior to June 30, 2023.

(3) Adjustment to Test Year rate base to include post-Test Year plant additions for Nuclear Generation with an estimated in-service date prior to June 30, 2023.

Supporting Schedules:
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(4) Distribution and IT/Facilities Post-Test Year Plant Additions		(5) Customer Technology Innovation Post-Test Year Plant Additions		(6) Renewable Generation Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 548,151	$ 521,962	$ 16,795	$ 16,795	$ 539,586	$ 539,586
2.	Less: Accumulated Depreciation & Amort.	354,671	340,356	-	-	27,272	27,272
3.	Net Utility Plant in Service	193,480	181,605	16,795	16,795	512,314	512,314
4.	Less: Total Deductions	(8,232)	(7,403)	436	436	88,831	88,831
5.	Total Additions	-	-	-	-	8,113	8,113
6.	Total Rate Base	$ 201,712	$ 189,009	$ 16,359	$ 16,359	$ 431,597	$ 431,597
	PRO FORMA WITNESS:	TETLOW		TETLOW		TETLOW	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Distribution facilities functionalized on Distribution (Schedule G-7 lines 10-16) and IT/Facilities functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)		1. ACC Specific 2. Functionalized on Distribution (Schedule G-7 lines 10-16)		1. ACC Specific 2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)	

(4) Adjustment to Test Year rate base to include post-Test Year plant additions for Distribution and IT/Facilities with an estimated in-service date prior to June 30, 2023.

(5) Adjustment to Test Year rate base to include post-Test Year plant additions for Customer Technology Innovation with an estimated in-service date prior to June 30, 2023.

(6) Adjustment to Test Year rate base to include post-Test Year Plant Additions for Renewable Generation with an estimated in-service date prior to June 30, 2023.

Supporting Schedules:
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(7) Include West Phoenix Unit 4 Regulatory Disallowance		(8) Adjust Cash Working Capital for Cost of Service		(9) Include Cloud Computing	
		Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(M)	(N)	(O)	(P)	(Q)	(R)
1.	Gross Utility Plant in Service	$ (13,833)	$ (13,816)	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	(7,418)	(7,410)	-	-	-	-
3.	Net Utility Plant in Service	(6,415)	(6,407)	-	-	-	-
4.	Less: Total Deductions	(1,586)	(1,584)	-	-	-	-
5.	Total Additions	-	-	(15,189)	(13,852)	22,229	20,272
6.	Total Rate Base	$ (4,829)	$ (4,823)	$ (15,189)	$ (13,852)	$ 22,229	$ 20,272
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)		1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)		1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)	

(7) Adjustment to Test Year rate base to include the regulatory disallowance for West Phoenix Unit 4 as required by Decision Nos. 67744 and 69663.

(8) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

(9) Adjustment to rate base to reflect the impacts of Cloud Computing in alignment with NARUC's Cloud Computing Resolution.

Supporting Schedules:
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(10) Include ADIT Impact from NGS Amortization Disallowance		(11) Include Four Corners SCR Regulatory Disallowance		(12) Include E-3/E-4 Customer Bill Payment Fees Deferral	
		Total Co. (S)	ACC (T)	Total Co. (U)	ACC (V)	Total Co. (W)	ACC (X)
1.	Gross Utility Plant in Service	$ -	$ -	$ (256,413)	$ (256,413)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3.	Net Utility Plant in Service	-	-	(256,413)	(256,413)	-	-
4.	Less: Total Deductions	(2,128)	(2,123)	(40,913)	(40,913)	-	-
5.	Total Additions	-	-	-	-	574	574
6.	Total Rate Base	$ 2,128	$ 2,123	$ (215,500)	$ (215,500)	$ 574	$ 574
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)		1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)	

(10) Adjustment to Test Year rate base to remove 15% of ADIT related to the regulatory asset for Navajo Generating Station (NGS) unrecovered plant costs from rate base as required by Decision No. 78317.

(11) Adjustment to Test Year rate base to reflect the Four Corners Selective Catalytic Reduction (SCR) disallowance as required by Decision No. 78317.

(12) Adjustment to Test Year rate base to include the estimated E-3/E-4 customer bill payment fees deferral amount from July 1, 2022 to December 1, 2023 (estimated rate effective date) as authorized by Decision No. 78317.

Supporting Schedules:
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	Total Original Cost Rate Base Pro Forma Adjustments (b) Total Co. (Y)	(b) ACC (Z)	Adjusted at End of Test Year 6/30/2022 (b) Total Co. (AA)	(b) ACC (AB)	Line No.
1.	Gross Utility Plant in Service	$ 1,198,620	$ 1,172,010	$ 24,590,594	$ 20,935,623	1.
2.	Less: Accumulated Depreciation & Amort.	611,123	$ 596,533	9,136,728	8,024,621	2.
3.	Net Utility Plant in Service	587,498	575,477	15,453,867	12,911,003	3.
4.	Less: Total Deductions	25,048	25,896	6,899,535	6,756,046	4.
5.	Total Additions	15,727	15,107	4,592,029	4,360,917	5.
6.	Total Rate Base	$ 578,176	$ 564,688	$ 13,146,360	$ 10,515,874	6.

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]

Supporting Schedules:
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-3
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(1) Actual at End of Test Year 6/30/2022 (a) (b) Total Co. (A)	(1) Actual at End of Test Year 6/30/2022 (a) (b) ACC (B)	(2) Other Generation Post-Test Year Plant Additions Total Co. (C)	(2) Other Generation Post-Test Year Plant Additions ACC (D)	(3) Nuclear Generation Post-Test Year Plant Additions Total Co. (E)	(3) Nuclear Generation Post-Test Year Plant Additions ACC (F)
1.	Gross Utility Plant in Service	$ 46,215,482	$ 39,046,936	$ 300,928	$ 300,567	$ 63,405	$ 63,329
2.	Less: Accumulated Depreciation & Amort.	16,727,637	14,574,257	222,290	222,023	14,308	14,291
3	Net Utility Plant in Service	29,487,845	24,472,679	78,638	78,544	49,097	49,038
4.	Less: Total Deductions	6,874,487	6,730,148	(14,269)	(14,251)	2,907	2,904
5.	Total Additions	4,576,302	4,345,812	-	-	-	-
6.	Total Rate Base	$ 27,189,660	$ 22,088,343	$ 92,907	$ 92,795	$ 46,190	$ 46,134

PRO FORMA WITNESS:

BLANKENSHIP

BLANKENSHIP

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]

1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)

1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1.

(2) Adjustment to Test Year rate base to include post-Test Year plant additions for Other Generation with an estimated in-service date prior to June 30, 2023.

(3) Adjustment to Test Year rate base to include post-Test Year plant additions for Nuclear Generation with an estimated in-service date prior to June 30, 2023.

Supporting Schedules
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-3
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(4) Distribution and IT/Facilities Post-Test Year Plant Additions		(5) Customer Technology Innovation Post-Test Year Plant Additions		(6) Renewable Generation Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 548,151	$ 521,962	$ 16,795	$ 16,795	$ 539,586	$ 539,586
2.	Less: Accumulated Depreciation & Amort.	354,671	340,356	-	-	27,272	27,272
3	Net Utility Plant in Service	193,480	181,605	16,795	16,795	512,314	512,314
4.	Less: Total Deductions	(8,232)	(7,403)	436	436	88,831	88,831
5.	Total Additions	-	-	-	-	8,113	8,113
6.	Total Rate Base	$ 201,712	$ 189,009	$ 16,359	$ 16,359	$ 431,597	$ 431,597

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Distribution facilities functionalized on Distribution (Schedule G-7 lines 10-16) and IT/Facilities functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)	1. ACC Specific 2. Functionalized on Distribution (Schedule G-7 lines 10-16	1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1; Schedule G-7 line 27)

(4) Adjustment to Test Year rate base to include post-Test Year plant additions for Distribution and IT/Facilities with an estimated in-service date prior to June 30, 2023.

(5) Adjustment to Test Year rate base to include post-Test Year plant additions for Customer Technology Innovation with an estimated in-service date prior to June 30, 2023.

(6) Adjustment to Test Year rate base to include post-Test Year Plant Additions for Renewable Generation with an estimated in-service date prior to June 30, 2023.

Supporting Schedules
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-3
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(7) Include West Phoenix Unit 4 Regulatory Disallowance		(8) Adjust Cash Working Capital for Cost of Service		(9) Include Cloud Computing	
		Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
1.	Gross Utility Plant in Service	$ (13,833)	$ (13,816)	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	(7,418)	(7,410)	-	-	-	-
3	Net Utility Plant in Service	(6,415)	(6,407)	-	-	-	-
4.	Less: Total Deductions	(1,586)	(1,584)	-	-	-	-
5.	Total Additions	-	-	(15,189)	(13,852)	22,229	20,272
6.	Total Rate Base	$ (4,829)	$ (4,823)	$ (15,189)	$ (13,852)	$ 22,229	$ 20,272
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)		1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)		1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)	

(7) Adjustment to Test Year rate base to include the regulatory disallowance for West Phoenix Unit 4 as required by Decision Nos. 67744 and 69663.

(8) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

(9) Increase to rate base to reflect the impacts of Cloud Computing in alignment with NARUC's Cloud Computing Resolution.

Supporting Schedules
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-3
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(10) Include ADIT Impact from NGS Amortization Disallowance		(11) Include Four Corners SCR Regulatory Disallowance		(12) Include E-3/E-4 Customer Bill Payment Fees Deferral	
		Total Co. (S)	ACC (T)	Total Co. (U)	ACC (V)	Total Co. (W)	ACC (X)
1.	Gross Utility Plant in Service	$ -	$ -	$ (256,413)	$ (256,413)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3	Net Utility Plant in Service	-	-	(256,413)	(256,413)	-	-
4.	Less: Total Deductions	(2,128)	(2,123)	(40,913)	(40,913)		
5.	Total Additions	-	-	-	-	574	574
6.	Total Rate Base	$ 2,128	$ 2,123	$ (215,500)	$ (215,500)	$ 574	$ 574
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)		1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)	

(10) Adjustment to Test Year rate base to remove 15% of ADIT related to the regulatory asset for Navajo Generating Station (NGS) unrecovered plant costs from rate base as required by Decision 78317.

(11) Adjustment to Test Year rate base to reflect the Four Corners Selective Catalytic Reduction (SCR) disallowance as required by Decision No. 78317.

(12) Adjustment to Test Year rate base to include the estimated E-3/E-4 customer bill payment fees deferral amount from July 1, 2022 to December 1, 2023 (estimated rate effective date) as authorized by Decision No. 78317.

Supporting Schedules
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-3
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(13) Total RCND Rate Base Pro Forma Adjustments (b) Total Co. (Y)	(b) ACC (Z)	(14) Adjusted at End of Test Year 6/30/2022 (b) Total Co. (AA)	(b) ACC (BB)
1.	Gross Utility Plant in Service	$ 1,198,620	$ 1,172,010	$ 47,414,102	$ 40,218,946
2.	Less: Accumulated Depreciation & Amort.	611,123	596,533	17,338,760	15,170,790
3	Net Utility Plant in Service	587,498	575,477	30,075,343	25,048,156
4.	Less: Total Deductions	25,048	25,896	6,899,535	6,756,044
5.	Total Additions	15,727	15,107	4,592,029	4,360,919
6.	Total Rate Base	$ 578,176 (a)	$ 564,688 (a)	$ 27,767,836 (a)	$ 22,653,031 (a)

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]

Supporting Schedules
(a) B-4a

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-4
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN	CONDITION PERCENT	RCND	Line No.
				(A)	(B)	(C)	
1.	INTANGIBLES	301	Organization	$ -	0.00%	$ -	1.
2.		302	Franchises and consents	3,809	38.37%	1,462	2.
3.		303	Miscellaneous intangible plant	1,045,888	27.58%	288,410	3.
4.			SUBTOTAL	$ 1,049,698		$ 289,871	4.
5.	PRODUCTION	310	Land and Land Rights	5,363	100.00%	5,363	5.
6.		310	Limit Term Land Rights	64	0.00%	-	6.
7.		311	Structures and improvements	583,835	49.07%	286,488	7.
8.		312	Boiler plant equipment	3,689,965	53.54%	1,975,608	8.
9.		314	Turbogenerator units	873,065	51.24%	447,358	9.
10.		315	Accessory electric equipment	1,042,655	44.94%	468,569	10.
11.		316	Miscellaneous power plant equipment	217,017	51.51%	111,786	11.
12.		317	ARO for Steam Production	69,152	66.47%	45,963	12.
13.		320	Land and land rights	4,418	100.00%	4,418	13.
14.		321	Structures and improvements	1,727,036	49.41%	853,607	14.
15.		322	Reactor plant equipment	2,790,392	43.49%	1,213,541	15.
16.		323	Turbogenerator units	922,714	48.68%	449,177	16.
17.		324	Accessory electric equipment	1,412,560	37.55%	530,416	17.
18.		325	Miscellaneous power plant equipment	480,284	61.63%	295,999	18.
19.		326	ARO for Nuclear Production	(1,335)	0.00%	-	19.
20.		330	Limit Term Land Rights	-	0.00%	-	20.
21.		331	Structures and improvements	-	0.00%	-	21.
22.		332	Reservoirs, dams, and waterways	-	0.00%	-	22.
23.		333	Water wheels, turbines and generators	-	0.00%	-	23.
24.		334	Accessory electric equipment	-	0.00%	-	24.
25.		335	Miscellaneous power plant equipment	-	0.00%	-	25.
26.		336	Roads, railroads and bridges	-	0.00%	-	26.
27.		337	ARO for Hydraulic Production	-	0.00%	-	27.
28.		340	Land and land rights	16,108	100.00%	16,108	28.
29.		341	Structures and improvements	372,158	71.40%	265,721	29.
30.		342	Fuel holders, products, and accessories	126,959	53.26%	67,618	30.
31.		343	Prime movers	2,244,732	60.39%	1,355,594	31.
32.		344	Generators	3,106,134	82.21%	2,553,553	32.
33.		345	Accessory electric equipment	574,909	73.09%	420,201	33.
34.		346	Miscellaneous power plant equip.	118,084	72.21%	85,269	34.
35.		347	ARO for Other Production	29,871	86.11%	25,723	35.
36.			SUBTOTAL	$ 20,406,139		$ 11,478,079	36.
37.	TRANSMISSION	350	Land and land rights	159,077	100.00%	159,077	37.
38.		350	Limit Term Land Rights	86,938	45.50%	39,553	38.
39.		352	Structures and improvements	335,451	27.23%	91,343	39.
40.		353	Station equipment	2,960,433	76.74%	2,271,836	40.
41.		354	Towers and fixtures	194,766	54.87%	106,868	41.
42.		355	Poles and fixtures	1,131,348	73.27%	828,939	42.
43.		356	Overhead conductors and devices	1,574,313	64.00%	1,007,561	43.
44.		357	Underground conduit	70,799	71.56%	50,665	44.
45.		358	Underground conductors and devices	188,503	84.04%	158,421	45.
46.			SUBTOTAL	$ 6,701,628		$ 4,714,263	46.

Supporting Schedules:
RCND Study

Recap Schedules:
(a) B-3

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-4
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN	CONDITION PERCENT	RCND	*Line No.*
				(A)	*(B)*	*(C)*	
47.	DISTRIBUTION	360	Land and land rights	68,386	100.00%	68,386	*47.*
48.		360	Limit Term Land Rights	15,927	61.47%	9,790	*48.*
49.		361	Structures and improvements	195,557	74.08%	144,869	*49.*
50.		362	Station equipment	1,510,228	78.81%	1,190,212	*50.*
51.		363	Storage Battery Equipment	5,344	87.33%	4,667	*51.*
52.		364	Poles, towers, and fixtures	1,447,958	82.16%	1,189,571	*52.*
53.		365	Overhead conductors and devices	1,129,935	81.60%	921,861	*53.*
54.		366	Underground conduit	1,415,891	72.07%	1,020,433	*54.*
55.		367	Underground conductors and devices	4,851,014	67.55%	3,276,860	*55.*
56.		368	Line transformers	3,668,250	72.34%	2,653,612	*56.*
57.		369	Services	891,186	69.07%	615,542	*57.*
58.		370	Meters	471,601	59.85%	282,271	*58.*
59.		371	Installations on customers' premises	125,165	84.51%	105,777	*59.*
60.		373	Street lighting and signal systems	226,505	70.08%	158,734	*60.*
61.			SUBTOTAL	$ 16,022,947		$ 11,642,584	*61.*
62.	GENERAL	389	Land and land rights	23,117	100.00%	23,117	*62.*
63.		390	Structures and improvements	676,299	83.75%	566,400	*63.*
64.		390	Structures and improvements - Lease	-	0.00%	-	*64.*
65.		391	Office furniture and equipment	515,999	54.58%	281,632	*65.*
66.		391	Capitalized Lease-Computer Equipment	-	54.58%	-	*66.*
67.		392	Transportation equipment	62,415	31.59%	19,537	*67.*
68.		392	Capitalized Lease-Transportation Equipmer	-	0.00%	-	*68.*
69.		393	Stores equipment	8,044	72.59%	5,839	*69.*
70.		394	Tools, shop and garage equipment	102,635	51.87%	53,237	*70.*
71.		395	Laboratory equipment	4,845	35.80%	1,735	*71.*
72.		396	Power operated equipment	25,976	27.65%	7,181	*72.*
73.		397	Communication equipment	570,642	65.02%	371,031	*73.*
74.		398	Miscellaneous equipment	45,098	73.59%	33,337	*74.*
75.			SUBTOTAL	$ 2,035,070		$ 1,363,047	*75.*
76.		TOTAL PLANT (a)		$ 46,215,482		$ 29,487,845	*76.*

Supporting Schedules:
RCND Study

Recap Schedules:
(a) B-3

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-4a
COMPUTATION OF RCND RATE BASE ELEMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.		Description	Total Company (B + C) (A)	ACC (B)	All Other (C)	Line No.
1.	A.	ORIGINAL COST:				1.
2.		Gross Utility Plant in Service	$ 23,391,974	$ 19,763,613	$ 3,628,361	2.
3.		Accumulated Depreciation & Amortization	8,525,605	7,428,088	1,097,517	3.
4.		Net Utility Plant in Service	14,866,369	12,335,525	2,530,844	4.
5.	B.	RCND:				5.
6.		Reproduction Cost New (a) (b)	46,215,482	39,046,936	7,168,546	6.
7.		Accumulated Depreciation (a) (b)	16,727,637	14,574,257	2,153,380	7.
8.		Total RCND Plant in Service (a) (b)	29,487,845	24,472,679	5,015,166	8.
9.		Deductions:				9.
10.		Deferred Income Taxes	2,354,272	2,352,811	1,461	10.
11.		Deferred Investment Tax Credits	184,032	181,609	2,423	11.
12.		Total Deferred Taxes and ITC	2,538,304	2,534,420	3,884	12.
13.		Customer Advances	336,198	305,254	30,944	13.
14.		Customer Deposits	40,063	40,063	-	14.
15.		Liabilities for Pension Benefits	89,240	88,065	1,175	15.
16.		Liability for Asset Retirement	784,472	774,145	10,327	16.
17.		Other Deferred Credits	21,110	20,832	278	17.
18.		Coal Mine Reclamation	176,936	174,607	2,329	18.
19.		Unrecognized Tax Benefits	37,662	37,166	496	19.
20.		Operating Lease Liabilities	843,713	647,798	195,915	20.
21.		Regulatory Liabilities	2,006,789	2,107,798	(101,009)	21.
22.		Total Deductions (a)	6,874,487	6,730,148	144,339	22.
23.		Additions:				23.
24.		Regulatory Assets	1,182,539	1,242,061	(59,522)	24.
25.		Other Deferred Debits	30,089	28,369	1,720	25.
26.		Nuclear Decommissioning Trust	1,076,088	1,074,797	1,291	26.
27.		Other Special Use Funds	346,406	345,990	416	27.
28.		Assets For Other Post-retirement Benefits	568,515	518,467	50,048	28.
29.		Operating Lease Right-Of-Use Assets	866,182	665,050	201,132	29.
30.		Allowance for Working Capital	506,483	471,078	35,405	30.
31.		Total Additions (a)	4,576,302	4,345,812	230,490	31.
32.		Total RCND Rate Base Before Pro forma Adj. (a)	27,189,660	22,088,343	5,101,317	32.
33.		Pro forma Adjustments (a)	578,176	564,688	13,488	33.
34.		Total RCND Rate Base (a)	$ 27,767,836	$ 22,653,031	$ 5,114,805	34.

Supporting Schedules:
For Lines 2-3 Col. (A): See Schedule B-1, Column (A) page 1 of 2.
For Lines 2-3 Col. (B): See Schedule B-1, Column (D) page 1 of 2.
For Lines 6-32 Col. (A): See Schedule B-1 (2), Column (A) page 2 of 2.
For Lines 6-32 Col. (B): See Schedule B-1 (2), Column (D) page 2 of 2.
For Line 33 Col. (A): See Schedule B-1 (2), Column (B), Line 24, page 2 of 2.
For Line 33 Col. (B): See Schedule B-1 (2), Column (E), Line 24, page 2 of 2.
For Line 34 Col. (A): See Schedule B-1 (2), Column (C), Line 24, page 2 of 2.
For Line 34 Col. (B): See Schedule B-1 (2), Column (F), Line 24, page 2 of 2.
(b) B-4

Recap Schedules:
(a) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-5
COMPUTATION OF WORKING CAPITAL
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	Amount *(A)*	*Line No.*
1.	Working Capital - Operations (a)	$ (105,488)	*1.*
2.	Materials and Supplies (b)	371,655	*2.*
3.	Fuel - Coal and Oil (b)	29,827	*3.*
4.	Fuel - Nuclear, Net (b)	132,696	*4.*
5.	Prepayments	74,020	*5.*
6.	Special Deposits & Working Funds	3,773	*6.*
7.	Total Allowance for Working Capital (c)	$ 506,483	*7.*

Supporting Schedules:
(a) Lead-Lag Study
(b) E-1

Recap Schedule
(c) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-1
INCOME STATEMENT
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	Total Company: Actual For The Test Year Ended 6/30/2022 (a) (A)	Pro forma Adjustments (b) (B)	Test Year Results After Pro forma Adjustments (c) (C)	Line No.
	Operating revenues:				
1.	Revenues from base rates	$ 3,409,458	$ (21,201)	$ 3,388,257	1.
2.	Revenues from surcharges	209,593	(209,593)	(0)	2.
3.	Other electric revenues	362,774	-	362,774	3.
4.	Total	3,981,825	(230,794)	3,751,031	4.
	Operating expenses:				
5.	Fuel and purchased power	1,335,138	67,001	1,402,139	5.
6.	Operations and maintenance	829,446	28,880	858,326	6.
7.	Depreciation and amortization	703,703	117,008	820,711	7.
8.	Income taxes	115,485	(113,750)	1,735	8.
9.	Taxes other than income taxes	253,435	18,226	271,661	9.
10.	Total	3,237,207	117,365	3,354,572	10.
11.	Operating income	744,618	(348,160)	396,458	11.
	Other income (deductions):				
12.	Income taxes	6,122	-	6,122	12.
13.	Allowance for equity funds used during construction	44,373	-	44,373	13.
14.	Other income	25,759	-	25,759	14.
15.	Other expense	(20,096)	-	(20,096)	15.
16.	Total	56,158	-	56,158	16.
17.	Income before interest deductions	800,776	(348,160)	452,616	17.
	Interest expense:				
18.	Interest charges	250,332	-	250,332	18.
19.	Allowance for borrowed funds used during construction	(20,970)	-	(20,970)	19.
20.	Total	229,362	-	229,362	20.
21.	Net income	$ 571,414	$ (348,160)	$ 223,254	21.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-1
INCOME STATEMENT
ACC JURISDICTIONAL
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	ACC Jurisdictional: Actual For The Test Year Ended 6/30/2022 (A)	Pro forma Adjustments (a) (B)	Test Year Results After Pro forma Adjustments (C)		Line No.
	Operating revenues:					
1.	Revenues from base rates	$ 3,398,013	$ (21,201)	$ 3,376,812		1.
2.	Revenues from surcharges	209,412	(209,412)	(0)		2.
3.	Other electric revenues	251,851	-	251,851		3.
4.	Total	3,859,277	(230,613)	3,628,663		4.
	Operating expenses:					
5.	Fuel and purchased power	1,195,285	67,322	1,262,606		5.
6.	Operations and maintenance	1,186,491	30,557	1,217,047		6.
7.	Depreciation and amortization	621,503	112,762	734,265		7.
8.	Income taxes	85,109	(112,186)	(27,077)		8.
9.	Taxes other than income taxes	187,775	16,196	203,971		9.
10.	Total	3,276,163	114,649	3,390,812		10.
11.	Operating income	583,113	(345,262)	237,851	(b)	11.
	Other income (deductions):					
12.	Income taxes	-	-			12.
13.	Allowance for equity funds used during construction	-	-			13.
14.	Other income	-	-			14.
15.	Other expense	-	-			15.
16.	Total	-				16.
17.	Income before interest deductions	583,113	(345,262)	237,851		17.
	Interest deductions (income):					
18.	Interest charges	-	-			18.
19.	Allowance for borrowed funds used during construction	-	-			19.
20.	Total	-	-	-		20.
21.	Net income	$ 583,113	$ (345,262)	$ 237,851		21.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description		(1) Other Generation Post-Test Year Plant Additions Total Co. (A)	(1) Other Generation Post-Test Year Plant Additions ACC (B)	(2) Nuclear Generation Post-Test Year Plant Additions Total Co. (C)	(2) Nuclear Generation Post-Test Year Plant Additions ACC (D)	(3) Distribution and IT/Facilities Post-Test Year Plant Additions Total Co. (E)	(3) Distribution and IT/Facilities Post-Test Year Plant Additions ACC (F)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Opera ions Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Deprecia ion and Amortization		13,036	13,020	197	196	30,092	28,035
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		1,670	1,668	355	355	8,777	8,363
14.	Total Other Operating Expense		14,705	14,688	551	551	38,869	36,398
15.	Operating Income Before Income Tax		(14,705)	(14,688)	(551)	(551)	(38,869)	(36,398)
16.	Interest Expense (b)	1.85%	1,719	1,717	855	853	3,732	3,497
17.	Taxable Income		(16,424)	(16,404)	(1,406)	(1,404)	(42,601)	(39,894)
18.	Current Income Tax Rate (c) -	24.72%	(4,060)	(4,055)	(348)	(347)	(10,531)	(9,862)
19.	Operating Income *(line 15 minus line 18)*		(10,645)	(10,632)	$ (204)	$ (204)	$ (28,338)	$ (26,536)

	(1) Other Generation Post-Test Year Plant Additions	(2) Nuclear Generation Post-Test Year Plant Additions	(3) Distribution and IT/Facilities Post-Test Year Plant Additions
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)	1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)	1. Jurisdictional 2. Distribution facilities func ionalized on Distribution (Schedule G-7 lines 10-16) and IT/Facilities functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)

(1) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income taxes associated with O her Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 2.

(2) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Nuclear Genera ion Post-Test Year Plant Addi ions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

(3) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Distribution and IT/Facilities Post-Test Year Plant Addi ions. Pro forma adjusted as shown on Schedule B-2, page 2, column 4.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(4) Customer Technology Innovation Post-Test Year Plant Additions Total Co. (G)	(4) ACC (H)	(5) Renewable Generation Post-Test Year Plant Addi ions Total Co. (I)	(5) ACC (J)	(6) Base Fuel and Purchased Power Costs Total Co. (K)	(6) ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	1,177	1,177
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(1,177)	(1,177)
	O her Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	1,680	1,680	20,943	20,943	-	-
11.	Amor iza ion of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	263	263	1,777	1,777	-	-
14.	Total Other Operating Expense	1,942	1,942	22,720	22,720	-	-
15.	Operating Income Before Income Tax	(1,942)	(1,942)	(22,720)	(22,720)	(1,177)	(1,177)
16.	Interest Expense (b) 1.85%	303	303	7,985	7,985	-	-
17.	Taxable Income	(2,245)	(2,245)	(30,704)	(30,704)	(1,177)	(1,177)
18.	Current Income Tax Rate (c) - 24.72%	(555)	(555)	(7,590)	(7,590)	(291)	(291)
19.	Operating Income *(line 15 minus line 18)*	$ (1,387)	$ (1,387)	$ (15,130)	$ (15,130)	$ (886)	$ (886)

	(4)	(5)	(6)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	MOE
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Functionalize as Distribution (Schedule G-7 lines 10-16)	1. ACC Specific 2. Renewables functionalized on Produc ion Demand (Retail DEMPROD1; Schedule G-7 line 27)	1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2; G-7 line 30)

(4) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Customer Technology Innovation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 5.

(5) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Renewable Genera ion Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 6.

(6) Adjustment to Test Year operations to reflect a modified 2023 forecasted base fuel and purchased power ¢/kWh rate at adjusted Test Year consump ion levels.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(7) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals Total Co. (M)	(7) ACC (N)	(8) Chemical O&M Total Co. (O)	(8) ACC (P)	(9) Normalize Weather Conditions Total Co. (Q)	(9) ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ 24,168	$ 24,168
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	O her Electric Revenues	-	-	-	-	-	-
4.	Total Electric Opera ing Revenues	-	-	-	-	24,168	24,168
5.	Electric Fuel and Purchased Power Costs	212,280	212,280	-	-	10,645	10,645
6.	Oper Rev Less Fuel & Purch Pwr Costs	(212,280)	(212,280)	-	-	13,523	13,523
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	7,135	7,135	-	-
9.	Subtotal	-	-	7,135	7,135	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administra ive and General	-	-	-	-	-	-
13.	O her Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	7,135	7,135	-	-
15.	Operating Income Before Income Tax	(212,280)	(212,280)	(7,135)	(7,135)	13,523	13,523
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	(212,280)	(212,280)	(7,135)	(7,135)	13,523	13,523
18.	Current Income Tax Rate (c) - 24.72%	(52,476)	(52,476)	(1,764)	(1,764)	3,343	3,343
19.	Operating Income *(line 15 minus line 18)*	(159,804)	(159,804)	$ (5,371)	$ (5,371)	$ 10,180	$ 10,180
	PRO FORMA WITNESS:	MOE		MOE		HOBBICK	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to Production - Energy (Retail ENERGY2_XAG1; Schedule G-7 line 31)		1. ACC Specific 2. Assigned to Production - Energy (Retail ENERGY2_XAG1; Schedule G-7 line 31)		1. ACC Specific 2. Revenues and Expenses are class specific (Direct Assignment (DIR Norm Weather; COS Model, Cost of Service tab line 2810)	

(7) Adjustment to Test Year retail fuel and purchased power costs to account for Test Year retail PSA deferred expenses and non-cash mark-to-market accruals.

(8) Adjustment to Test Year operations to set base environmental chemical cost rate at Test Year chemical cost levels.

(9) Adjustment to Test Year operating revenues to reflect normal weather conditions for he ten years ended June 30, 2022.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(10) Annualize Customer Levels Total Co. (S)	(10) Annualize Customer Levels ACC (T)	(11) Remove Power Supply Adjustor (PSA) Revenue & Deferred Fuel Amortization Total Co. (U)	(11) Remove Power Supply Adjustor (PSA) Revenue & Deferred Fuel Amortization ACC (V)	(12) Remove Test Year Regulatory Assessment Total Co. (W)	(12) Remove Test Year Regulatory Assessment ACC (X)
	Electric Opera ing Revenues						
1.	Revenues from Base Rates	$ 26,132	$ 26,132	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	(130,571)	(130,259)	(8,064)	(8,064)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	26,132	26,132	(130,571)	(130,259)	(8,064)	(8,064)
5.	Electric Fuel and Purchased Power Costs	10,522	10,522	(128,856)	(128,547)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	15,610	15,610	(1,715)	(1,711)	(8,064)	(8,064)
	Other Opera ing Expenses:						
7.	Operations Excluding Fuel Expense	-	-	(1,715)	(1,711)	(8,064)	(8,064)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	(1,715)	(1,711)	(8,064)	(8,064)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total O her Operating Expense	-	-	(1,715)	(1,711)	(8,064)	(8,064)
15.	Operating Income Before Income Tax	15,610	15,610	(0)	-	-	-
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	15,610	15,610	(0)	-	-	-
18.	Current Income Tax Rate (c) - 24.72%	3,859	3,859	(0)	-	-	-
19.	Operating Income *(line 15 minus line 18)*	$ 11,751	$ 11,751	$ (0)	$ -	$ -	$ -
	PRO FORMA WITNESS:	HOBBICK		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Revenues and Expenses are class specific. (Direct Assignment (DIR Ann Customers; COS Model, Cost of Service tab line 2813)		1. ACC Specific 2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. ACC Specific 2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)	

(10) Adjustment to Test Year operating revenues to reflect he annualization of customer levels at June 30, 2022.

(11) Adjustment to Test Year operations to remove retail PSA revenue and deferred fuel amortization related to prior periods.

(12) Adjustment to Test Year operations to remove the Regulatory Assessment surcharges from operating revenues and expenses.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(13) Remove Test Year Transmission Cost Adjustor (TCA) Total Co. (Y)	(13) ACC (Z)	(14) Transfer Test Year Lost Fixed Cost Recovery (LFCR) Total Co. (AA)	(14) ACC (AB)	(15) Transfer Test Year Environmental Improvement Surcharge (EIS) Total Co. (AC)	(15) ACC (AD)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	5,144	4,984	(27,149)	(27,149)	(10,355)	(10,334)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	5,144	4,984	(27,149)	(27,149)	(10,355)	(10,334)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	5,144	4,984	(27,149)	(27,149)	(10,355)	(10,334)
	O her Operating Expenses:						
7.	Operations Excluding Fuel Expense	5,144	4,984	31,360	31,360	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	5,144	4,984	31,360	31,360	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amor iza ion of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	5,144	4,984	31,360	31,360	-	-
15.	Operating Income Before Income Tax	-	-	(58,509)	(58,509)	(10,355)	(10,334)
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	-	-	(58,509)	(58,509)	(10,355)	(10,334)
18.	Current Income Tax Rate (c) - 24.72%	-	-	(14,464)	(14,464)	(2,560)	(2,555)
19.	Operating Income *(line 15 minus line 18)*	$ -	$ -	$ (44,046)	$ (44,046)	$ (7,795)	$ (7,779)
	PRO FORMA WITNESS:	BLANKENSHIP		HOBBICK/BLANKENSHIP		HOBBICK/BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to Produc ion Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. ACC Specific 2. Assigned to Produc ion Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. ACC Specific 2. Assigned to Produc ion Demand (Retail DEMPROD1; Schedule G-7 line 27)	

(13) Adjustment to Test Year operations to remove the TCA from operating revenues and expenses.

(14) Adjustment to Test Year operations to transfer LFCR to base rates.

(15) Adjustment to Test Year operations to reflect the eimlination of he EIS surcharge.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(16) Transfer Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense		(17) Remove Renewable Energy Adjustment Charge (REAC)		(18) Annualize Test Year Tax Expense Adjustor Mechanism (TEAM I, II, & III)	
		Total Co. (AE)	ACC (AF)	Total Co. (AG)	ACC (AH)	Total Co. (AI)	ACC (AJ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(39,467)	(39,405)	(70,835)	(70,811)	71,704	71,625
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(39,467)	(39,405)	(70,835)	(70,811)	71,704	71,625
5.	Electric Fuel and Purchased Power Costs	-	-	(39,385)	(39,372)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(39,467)	(39,405)	(31,449)	(31,439)	71,704	71,625
	O her Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	(31,449)	(31,439)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	(31,449)	(31,439)	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amor iza ion of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	(31,449)	(31,439)	-	-
15.	Operating Income Before Income Tax	(39,467)	(39,405)	0	0	71,704	71,625
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	(39,467)	(39,405)	0	0	71,704	71,625
18.	Current Income Tax Rate (c) - 24.72%	(9,756)	(9,741)	0	0	17,725	17,706
19.	Operating Income *(line 15 minus line 18)*	$ (29,711)	$ (29,664)	$ 0	$ 0	$ 53,979	$ 53,920
	PRO FORMA WITNESS:	HOBBICK/BLANKENSHIP		BLANKENSHIP		HOBBICK/BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. ACC Specific 2. Assigned to Produc ion Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. Jurisdictional 2. Revenues and Expenses are class specific (Direct Assignment (DIR TEAM; COS Model, Cost of Service tab line 2846 column 4)	

(16) Adjustment to Test Year operations to transfer revenues from the DSM to base revenues.

(17) Adjustment to Test Year operations to remove the REAC from operating revenues.

(18) Adjustment to Test Year operations to annualize the TEAM adjustor that was moved to base revenues in Decision No. 78317. The TEAM mechanism was set to zero in Decision No. 78317.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description		(19) Base Revenue Annualization Total Co. (AK)	(19) Base Revenue Annualization ACC (AL)	(20) Include West Phoenix Unit 4 Regulatory Disallowance Total Co. (AM)	(20) Include West Phoenix Unit 4 Regulatory Disallowance ACC (AN)	(21) Include Interest Expense on Customer Deposits Total Co. (AO)	(21) Include Interest Expense on Customer Deposits ACC (AP)
	Electric Opera ing Revenues							
1.	Revenues from Base Rates		$ (71,501)	$ (71,501)	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		(71,501)	(71,501)	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		(71,501)	(71,501)	-	-	-	-
	Other Opera ing Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	160	160
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	160	160
10.	Depreciation and Amortization		-	-	(329)	(329)	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total O her Operating Expense		-	-	(329)	(329)	160	160
15.	Operating Income Before Income Tax		(71,501)	(71,501)	329	329	(160)	(160)
16.	Interest Expense (b)	1.85%	-	-	(89)	(89)	-	-
17.	Taxable Income		(71,501)	(71,501)	418	418	(160)	(160)
18.	Current Income Tax Rate (c) -	24.72%	(17,675)	(17,675)	103	103	(40)	(40)
19.	Operating Income *(line 15 minus line 18)*		$ (53,826)	$ (53,826)	$ 226	$ 225	$ (121)	$ (121)
	PRO FORMA WITNESS:		HOBBICK		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]		1. ACC Specific 2. Direct Assignment (DIR Rev Norm; COS Model, Cost of Service tab line 2816 column 4)		1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)		1. ACC Specific 2. Assigned to Customer Accounts (CUSTDEP; Schedule G-7 line 40)	

(19) Adjustment to Test Year base revenues to annualize the change in rates approved in Decision No. 78317 and implemented on December 1, 2021.

(20) Adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by previous Decision Nos. 67744 and 69663. Rate Base pro forma adjusted as shown on Schedule B-2, page 3, column 7.

(21) Adjustment to Test Year operations to include he operating income impact of interest on customer deposits using he January 2022 interest rate.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(22) Include Proposed Limited Income Tiered Discount		(23) Amortize Limited Income Discount Deferral		(24) Customer Bill Payment Fees Proposal	
		Total Co. (AQ)	ACC (AR)	Total Co. (AS)	ACC (AT)	Total Co. (AU)	ACC (AV)
	Electric Opera ing Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Opera ing Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	10,641	10,641
8.	Maintenance	433	433	-	-	-	-
9.	Subtotal	433	433	-	-	10,641	10,641
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	6,425	6,425	2,058	2,058	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total O her Operating Expense	6,857	6,857	2,058	2,058	10,641	10,641
15.	Operating Income Before Income Tax	(6,857)	(6,857)	(2,058)	(2,058)	(10,641)	(10,641)
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	(6,857)	(6,857)	(2,058)	(2,058)	(10,641)	(10,641)
18.	Current Income Tax Rate (c) - 24.72%	(1,695)	(1,695)	(509)	(509)	(2,631)	(2,631)
19.	Operating Income *(line 15 minus line 18)*	$ (5,162)	$ (5,162)	$ (1,549)	$ (1,549)	$ (8,011)	$ (8,011)
	PRO FORMA WITNESS:	HOBBICK		HOBBICK		HOBBICK	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)		1. ACC Specific 2. Functionalized on Customer Accounts (CUSTNUM_A; Schedule G-7 line 6)	

(22) Adjustment to Test Year operations to reflect he increase necessary to adopt the proposed limited-income tiered discount.

(23) Adjustment to Test Year operations to amortize the limited-income discount deferral approved by the Commission in Decision No. 78317 over a three year period.

(24) Adjustment to Test Year operations to reflect customer bill payment fees proposal.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Descrip ion	(25) Annualize E-3/E-4 Customer Bill Payment Fees Deferral Amortization		(26) Annualize Depreciation Expense		(27) Annualize Payroll Expense	
		Total Co. (AW)	ACC (AX)	Total Co. (AY)	ACC (AZ)	Total Co. (BA)	ACC (BB)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	O her Electric Revenues	-	-	-	-	-	-
4.	Total Electric Opera ing Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	270	270	-	-	(1,741)	(1,588)
8.	Maintenance	-	-	-	-	(347)	(316)
9.	Subtotal	270	270	-	-	(2,088)	(1,904)
10.	Depreciation and Amortization	-	-	44,660	42,490	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administra ive and General	-	-	-	-	-	-
13.	O her Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	270	270	44,660	42,490	(2,088)	(1,904)
15.	Operating Income Before Income Tax	(270)	(270)	(44,660)	(42,490)	2,088	1,904
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	(270)	(270)	(44,660)	(42,490)	2,088	1,904
18.	Current Income Tax Rate (c) - 24.72%	(67)	(67)	(11,040)	(10,504)	516	471
19.	Operating Income *(line 15 minus line 18)*	$ (203)	$ (203)	$ (33,620)	$ (31,987)	$ 1,572	$ 1,433
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; G-7 line 32)		1. Jurisdictional 2. Assigned to PT&D; General and Intangible functionalized on Wages & Salaries		1. Jurisdic ional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)	

(25) Adjustment to Test Year operations to reflect amortization for the E-3/E-4 customer bill payment fees deferral au horized in Decision No. 78317 over a three year period. Pro forma adjusted as shown on Schedule B-2, page 4, column 12.

(26) Adjustment to Test Year operations to annualize depreciation expense as of June 30, 2022 using the deprecia ion study rates approved in Decision No. 78317.

(27) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax, and non-retirement benefit expenses to end of Test Year employee levels and wage levels.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(28) Normalize Employee Benefits Total Co. (BC)	(28) Normalize Employee Benefits ACC (BD)	(29) Remove Supplemental Executive Retirement Plan (SERP) Total Co. (BE)	(29) Remove Supplemental Executive Retirement Plan (SERP) ACC (BF)	(30) Remove Stock Compensation Total Co. (BG)	(30) Remove Stock Compensation ACC (BH)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	5,222	4,762	(7,579)	(6,912)	(11,304)	(10,309)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	5,222	4,762	(7,579)	(6,912)	(11,304)	(10,309)
10.	Depreciation and Amor iza ion	-	-	-	-	-	-
11.	Amor ization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	5,222	4,762	(7,579)	(6,912)	(11,304)	(10,309)
15.	Operating Income Before Income Tax	(5,222)	(4,762)	7,579	6,912	11,304	10,309
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	(5,222)	(4,762)	7,579	6,912	11,304	10,309
18.	Current Income Tax Rate (c) - 24.72%	(1,291)	(1,177)	1,874	1,709	2,794	2,548
19.	Operating Income *(line 15 minus line 18)*	$ (3,931)	$ (3,585)	$ 5,706	$ 5,204	$ 8,510	$ 7,761
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)		1. Jurisdic ional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)		1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)	

(28) Adjustment to Test Year opera ions to reflect change in benefit expense to current year 2022 actuarial valuation.

(29) Adjustment to Test Year opera ions to remove Supplemental Execu ive Retirement Plan benefits (SERP).

(30) Adjustment to Test Year opera ions to remove Stock Compensation expense.

Suppor ing Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(31) Include Active Union Medical Trust Interest Income and Realized Gains		(32) Normalize Cash Incentive Expense		(33) Normalize Income Tax Expense/Interest Synchronization	
		Total Co. (BI)	ACC (BJ)	Total Co. (BK)	ACC (BL)	Total Co. (BM)	ACC (BN)
	Electric Opera ing Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Opera ing Expenses:						
7.	Operations Excluding Fuel Expense	(3,539)	(3,228)	4,045	3,689	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(3,539)	(3,228)	4,045	3,689	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	4,130	3,766	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total O her Operating Expense	(3,539)	(3,228)	8,175	7,455	-	-
15.	Operating Income Before Income Tax	3,539	3,228	(8,175)	(7,455)	-	-
16.	Interest Expense (b) 1.85%	-	-	-	-	(11,992)	(13,650)
17.	Taxable Income	3,539	3,228	(8,175)	(7,455)	11,992	13,650
18.	Current Income Tax Rate (c) - 24.72%	875	798	(2,021)	(1,843)	2,964	3,374
19.	Operating Income *(line 15 minus line 18)*	$ 2,664	$ 2,430	$ (6,154)	$ (5,612)	$ (2,964)	$ (3,374)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdic ional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)		1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)		1. Jurisdictional 2. Calculated in pro forma workpaper.	

(31) Adjustment to Test Year operations to include interest income and realized gain on investments in the Ac ive Union Medical Trust Account.

(32) Adjustment to Test Year to normalize cash incentive expense over a three-year period.

(33) Adjustment to Test Year operations for top-down income tax true-ups consistent with prior Decisions using Test Year rate base and composite cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(34) Annualize Property Tax Expense Total Co. (BO)	(34) Annualize Property Tax Expense ACC (BP)	(35) Annualize Property Tax Deferral Amortization Total Co. (BQ)	(35) Annualize Property Tax Deferral Amortization ACC (BR)	(36) Include Amortization of Property Tax Residual Deferral Total Co. (BS)	(36) Include Amortization of Property Tax Residual Deferral ACC (BT)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Opera ions Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Deprecia ion and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	9,521	7,907	(1,946)	(1,946)	(2,189)	(2,189)
14.	Total Other Operating Expense	9,521	7,907	(1,946)	(1,946)	(2,189)	(2,189)
15.	Operating Income Before Income Tax	(9,521)	(7,907)	1,946	1,946	2,189	2,189
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	(9,521)	(7,907)	1,946	1,946	2,189	2,189
18.	Current Income Tax Rate (c) - 24.72%	(2,354)	(1,955)	481	481	541	541
19.	Operating Income *(line 15 minus line 18)*	$ (7,167)	$ (5,952)	$ 1,465	$ 1,465	$ 1,648	$ 1,648

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

BLANKENSHIP
1. Jurisdictional
2. Functionalized on PT&D (COS Model, FunctionDetail tab, row 89 column C)

BLANKENSHIP
1. ACC Specific
2. Distribution Property Tax functionalized on Distribution (Schedule G-7 lineds 10-16) and Generation Property Tax func ionalized on Demand Production (Retail DEMPROD1; Schedule G-7 line 27)

BLANKENSHIP
1.ACC Specific
2. Distribu ion Property Tax functionalized on Distribution (Schedule G-7 lineds 10-16) and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1; Schedule G-7 line 27)

(34) Adjustment to Test Year operations to annualize property taxes calculated using the anticipated 2023 tax assessment ratio and the 2021 actual composite tax rate.

(35) Adjustment to include the annualized amortiza ion of the property tax deferral as authorized in Decision No. 76295 and 78317 over three years.

(36) Adjustment to Test Year operations to reflect the amortization for the Property Tax residual deferral (January 2021 through the rate effective date of Decision No. 78317) over three years.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(37) Annualize Four Corners Coal Reclama ion Costs Total Co. (BU)	(37) ACC (BV)	(38) Annualize Navajo Coal Reclamation Costs Total Co. (BW)	(38) ACC (BX)	(39) Adjust Cash Working Capital for Cost of Service Total Co. (BY)	(39) ACC (BZ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(1,508)	(1,505)	2,127	2,122	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	1,508	1,505	(2,127)	(2,122)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amor iza ion	-	-	-	-	-	-
11.	Amor ization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	-	-	-	-
15.	Operating Income Before Income Tax	1,508	1,505	(2,127)	(2,122)	-	-
16.	Interest Expense (b) 1.85%	-	-	-	-	(281)	(256)
17.	Taxable Income	1,508	1,505	(2,127)	(2,122)	281	256
18.	Current Income Tax Rate (c) - 24.72%	373	372	(526)	(525)	69	63
19.	Operating Income *(line 15 minus line 18)*	$ 1,135	$ 1,133	$ (1,601)	$ (1,598)	$ (69)	$ (63)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)		1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)		1. Jurisdictional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)	

(37) Adjustment to Test Year opera ions to reflect the most recent Four Corners Power Plant coal reclamation study.

(38) Adjustment to Test Year opera ions to reflect the final Navajo Generating Station coal reclamation study and negotiations.

(39) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment. Pro forma adjusted as shown on Schedule B-2, page 3, column 8.

Suppor ing Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description		(40) Normalize Nuclear Maintenance Expense Total Co. (CA)	(40) Normalize Nuclear Maintenance Expense ACC (CB)	(41) Normalize Fossil Maintenance Expense Total Co. (CC)	(41) Normalize Fossil Maintenance Expense ACC (CD)	(42) Annualize Sundance Maintenance Expense Accrual Total Co. (CE)	(42) Annualize Sundance Maintenance Expense Accrual ACC (CF)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Opera ing Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		(431)	(430)	28,029	27,974	1,957	1,953
9.	Subtotal		(431)	(430)	28,029	27,974	1,957	1,953
10.	Depreciation and Amor ization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total O her Operating Expense		(431)	(430)	28,029	27,974	1,957	1,953
15.	Operating Income Before Income Tax		431	430	(28,029)	(27,974)	(1,957)	(1,953)
16.	Interest Expense (b)	1.85%	-	-	-	-	-	-
17.	Taxable Income		431	430	(28,029)	(27,974)	(1,957)	(1,953)
18.	Current Income Tax Rate (c) -	24.72%	107	106	(6,929)	(6,915)	(484)	(483)
19.	Operating Income *(line 15 minus line 18)*		$ 325	$ 324	$ (21,101)	$ (21,059)	$ (1,473)	$ (1,470)

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

BLANKENSHIP
1. Jurisdic ional
2. Assigned to Production - Energy
(ENERGY1; Schedule G-7 line 22)

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Energy
(ENERGY1; Schedule G-7 line 22)

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Energy
(ENERGY1; Schedule G-7 line 22)

(40) Adjustment to Test Year operations to reflect hree-year normalization of nuclear produc ion maintenance expense.

(41) Adjustment to Test Year operations to reflect six-year normalization of fossil produc ion maintenance expense.

(42) Adjustment to Test Year operations to annualize the accrual of Sundance maintenance costs as authorized in Decision Nos. 69663 and 78317.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Descrip ion		(43) Remove Navajo Power Plant Costs Total Co. (CG)	(43) Remove Navajo Power Plant Costs ACC (CH)	(44) Include Navajo Regulatory Asset Amortization Disallowance Total Co. (CI)	(44) Include Navajo Regulatory Asset Amortization Disallowance ACC (CJ)	(45) Annualize Oco illo Moderniza ion Project (OMP) Deferral Amor iza ion Total Co. (CK)	(45) Annualize Oco illo Moderniza ion Project (OMP) Deferral Amor iza ion ACC (CL)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	O her Electric Revenues		-	-	-	-	-	-
4.	Total Electric Opera ing Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		(169)	(168)	-	-	-	-
8.	Maintenance		(4)	(4)	-	-	-	-
9.	Subtotal		(173)	(173)	-	-	-	-
10.	Depreciation and Amortization		-	-	(1,441)	(1,438)	3,961	3,961
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administra ive and General		117	117	-	-	-	-
13.	O her Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(56)	(56)	(1,441)	(1,438)	3,961	3,961
15.	Operating Income Before Income Tax		56	56	1,441	1,438	(3,961)	(3,961)
16.	Interest Expense (b)	1.85%	-	-	-	-	-	-
17.	Taxable Income		56	56	1,441	1,438	(3,961)	(3,961)
18.	Current Income Tax Rate (c) -	24.72%	14	14	356	355	(979)	(979)
19.	Operating Income *(line 15 minus line 18)*		$ 42	$ 42	$ 1,085	$ 1,082	$ (2,982)	$ (2,982)

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Energy (ENERGY1; Schedule G-7 line 22)

BLANKENSHIP
1. Jurisdictional
2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)

BLANKENSHIP
1. ACC Specific
2. Assigned to Production - Demand (Retail DEMPROD1; Schedule G-7 line 27)

(43) Adjustment to Test Year operations to reflect the closure of the Navajo Genera ing Station.

(44) Adjustment to Test Year operations to record 15% disallowance of the annualized amortization expense related to he regulatory asset of Navajo Generating Station as required by Decision No. 78317. Pro forma adjusted as shown on Schedule B-2, page 4, column 10.

(45) Adjustment to Test Year operations to include the amortization of the OMP deferral as approved in Decision No. 78317 over ten years.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Descrip ion	(46) Include Amor ization of OMP Residual Deferral Total Co. (CM)	(46) ACC (CN)	(47) Include OMP Deferral Equity Return Disallowance Total Co. (CO)	(47) ACC (CP)	(48) Adjust Four Corners SCR Deprecia ion Expense Total Co. (CQ)	(48) ACC (CR)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	O her Electric Revenues	-	-	-	-	-	-
4.	Total Electric Opera ing Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	5,337	5,331	(4,387)	(4,387)	117	117
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administra ive and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Opera ing Expense	5,337	5,331	(4,387)	(4,387)	117	117
15.	Opera ing Income Before Income Tax	(5,337)	(5,331)	4,387	4,387	(117)	(117)
16.	Interest Expense (b) 1 85%	-	-	-	-	(3,987)	(3,979)
17.	Taxable Income	(5,337)	(5,331)	4,387	4,387	3,870	3,862
18.	Current Income Tax Rate (c) - 24.72%	(1,319)	(1,318)	1,084	1,084	957	955
19.	Opera ing Income *(line 15 minus line 18)*	$ (4,018)	$ (4,013)	$ 3,302	$ 3,302	$ (1,073)	$ (1,072)

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)

BLANKENSHIP
1. ACC Specific
2. Assigned to Produc ion Demand (Retail DEMPROD1; Schedule G-7 line 27)

BLANKENSHIP
1. ACC Specific
2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)

(46) Adjustment to Test Year operations to reflect the amortization for the OMP residual deferral (January 2021 through he rate effective date of Decision No. 78317) over ten years.

(47) Adjustment to Test Year operations to reflect the disallowance of the OMP Deferral Equity Return as required by Decision No. 78317.

(48) Adjustment to Test Year operations to reflect depreciation expense of the allowed remaining Four Corners SCR plant balance based on an end of life of 2031 ordered in Decision No. 78317.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(49) Annualize Four Corners SCR Deferral Amortization Total Co. (CS)	(49) ACC (CT)	(50) Include Amortization of Four Corners SCR Residual Deferral Total Co. (CU)	(50) ACC (CV)	(51) Annualize Cholla Inventory Total Co. (CW)	(51) ACC (CX)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-		-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amor iza ion	3,395	3,390	3,123	3,119	310	310
11.	Amor ization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	3,395	3,390	3,123	3,119	310	310
15.	Operating Income Before Income Tax	(3,395)	(3,390)	(3,123)	(3,119)	(310)	(310)
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	(3,395)	(3,390)	(3,123)	(3,119)	(310)	(310)
18.	Current Income Tax Rate (c) - 24.72%	(839)	(838)	(772)	(771)	(77)	(77)
19.	Operating Income *(line 15 minus line 18)*	$ (2,555)	$ (2,552)	$ (2,351)	$ (2,348)	$ (234)	$ (233)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Produc ion - Demand (DEMPROD1; Schedule G-7 line 17)		1. Jurisdic ional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)	

(49) Adjustment to Test Year opera ions to annualize he amortization for the Four Corners SCR deferral that was au horized in Decision No. 78317.

(50) Adjustment to Test Year opera ions to reflect the amor iza ion for the Four Corners SCR residual deferral (January 2021 hrough the rate effective date of Decision No. 78317) over ten years.

(51) Adjustment to Test Year opera ions to reflect the annualized level of amortization related to Cholla material and supplies inventory as accepted in Decision No. 78317.

Suppor ing Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description		(52) Annualize Four Corners Inventory Total Co. (CY)	(52) Annualize Four Corners Inventory ACC (CZ)	(53) Normalize Advertising Expense Total Co. (DA)	(53) Normalize Advertising Expense ACC (DB)	(54) Include Removal Costs Associated with he West Phoenix Steam Units Total Co. (DC)	(54) Include Removal Costs Associated with he West Phoenix Steam Units ACC (DD)
	Electric Opera ing Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	(1,652)	(1,652)	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	(1,652)	(1,652)	-	-
10.	Deprecia ion and Amortization		424	423	-	-	416	415
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total O her Operating Expense		424	423	(1,652)	(1,652)	416	415
15.	Operating Income Before Income Tax		(424)	(423)	1,652	1,652	(416)	(415)
16.	Interest Expense (b)	1.85%	-	-	-	-	-	-
17.	Taxable Income		(424)	(423)	1,652	1,652	(416)	(415)
18.	Current Income Tax Rate (c) -	24.72%	(105)	(105)	408	408	(103)	(103)
19.	Operating Income *(line 15 minus line 18)*		$ (319)	$ (319)	$ 1,244	$ 1,244	$ (313)	$ (313)

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

(52) Annualize Four Corners Inventory	(53) Normalize Advertising Expense	(54) Include Removal Costs Associated with he West Phoenix Steam Units
BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
1. Jurisdic ional	1. ACC Specific	1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)	2. Functionalized on Wages & Salaries less Transmission (COS Model, Function Detail tab, row 56 column C)	2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)

(52) Adjustment to Test Year operations to reflect he annualized level of amortization related to Four Corners material and supplies inventory as accepted in Decision No. 78317.

(53) Adjustment to Test Year operations to normalize advertising expense over a hree-year period.

(54) Adjustment to include the annualized amortization of cost of removal associated wi h decommissioning of the West Phoenix Steam Units 4, 5 & 6 as approved in Decision No. 78317.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(55) Remove Out of Period and Misc Items Total Co. (DE)	(55) Remove Out of Period and Misc Items ACC (DF)	(56) Amortize Cholla Unit 2 Regulatory Asset Total Co. (DG)	(56) Amortize Cholla Unit 2 Regulatory Asset ACC (DH)	(57) Annualize TEAM Balancing Account Amortization Total Co. (DI)	(57) Annualize TEAM Balancing Account Amortization ACC (DJ)
	Electric Opera ing Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Opera ing Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	(4,793)	(4,784)	273	273
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	(10,252)	(9,349)	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total O her Operating Expense	(10,252)	(9,349)	(4,793)	(4,784)	273	273
15.	Operating Income Before Income Tax	10,252	9,349	4,793	4,784	(273)	(273)
16.	Interest Expense (b) 1.85%	-	-	-	-	-	-
17.	Taxable Income	10,252	9,349	4,793	4,784	(273)	(273)
18.	Current Income Tax Rate (c) - 24.72%	2,534	2,311	1,185	1,183	(67)	(67)
19.	Operating Income *(line 15 minus line 18)*	$ 7,717	$ 7,038	$ 3,608	$ 3,601	$ (206)	$ (206)

	(55) Remove Out of Period and Misc Items	(56) Amortize Cholla Unit 2 Regulatory Asset	(57) Annualize TEAM Balancing Account Amortization
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdic ional 2. Functionalized on Wages & Salaries (COS Model, Function Detail tab, row 27 column C)	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)	1. ACC Specific 2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)

(55) Adjustment to Test Year operations to remove Out of Period and Miscellaneous Items from he Test Year.

(56) Adjustment to Test Year operations to annualize the amortization of the Decision No. 76295 Cholla Unit 2 Regulatory Asset & Liability over the remaining plant life pursuant to Decision No. 78317.

(57) Adjustment to Test Year operations to annualize amortization for the TEAM Balancing account as accpeted in Decision No. 78317 for ten years.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description	(58) Include Amortiza ion of TEAM Balancing Account Residual Total Co. (DK)	(58) ACC (DL)	(59) Amortize COVID Customer Relief Deferral Total Co. (DM)	(59) ACC (DN)	(60) Total Income Statement Adjustments (a) Total Co. (DO)	(60) (a) ACC (DP)
	Electric Opera ing Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ (21,201)	$ (21,201)
2.	Revenues from Surcharges	-	-	-	-	(209,593)	(209,412)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	(230,794)	(230,613)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	67,001	67,322
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(297,795)	(297,935)
	Other Opera ing Expenses:						
7.	Operations Excluding Fuel Expense		-		-	(10,370)	(9,204)
8.	Maintenance	-	-	-	-	36,772	36,744
9.	Subtotal	-	-	-	-	26,401	27,539
10.	Depreciation and Amortization	(604)	(604)	600	600	117,008	112,762
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	2,478	3,017
13.	Other Taxes	-	-	-	-	18,226	16,196
14.	Total O her Operating Expense	(604)	(604)	600	600	164,114	159,514
15.	Operating Income Before Income Tax	604	604	(600)	(600)	(461,909)	(457,449)
16.	Interest Expense (b) 1.85%	-	-	-	-	(1,757)	(3,620)
17.	Taxable Income	604	604	(600)	(600)	(460,152)	(453,829)
18.	Current Income Tax Rate (c) - 24.72%	149	149	(148)	(148)	(113,750)	(112,186)
19.	Operating Income *(line 15 minus line 18)*	$ 455	$ 455	$ (452)	$ (452)	$ (348,160)	$ (345,262)

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

BLANKENSHIP
1. ACC Specific
2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)

BLANKENSHIP
1. ACC Specific
2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)

(58) Adjustment to Test Year operations to reflect the amortization of the TEAM residual balance (January 2021 through the rate-effective date of Decision No. 78317) over eight years.

(59) Adjustment to Test Year operations to reflect the amortization of the COVID Customer Relief regulatory asset authorized in Decision No. 77849 over a hree year period.

Supporting Schedules:
(b) D-2
(c) C-3

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-3
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022

Line No.	Description		2022 Percentage of Incremental Gross Revenues	Line No.
1.	Gross Revenue		100%	1.
2.	Less uncollectible revenue		0.54%	2.
3.	Taxable revenue as a percent		99.47%	3.
4.	Federal Income Taxes*		20.89%	4.
5.	State Income Taxes Net of Federal Tax Benefit		3.72%	5.
6.	Total Tax Percentage**		24.61%	6.
7.	Tax Factor	*Line 3 - Line 6*	74.86%	7.
8.	Gross Revenue Conversion Factor	*(1 / Line 7) * 100*	1.3359	8.

* Federal Income Taxes (line 4) is calculated using the Federal Statutory Rate of 21% multiplied by Taxable Revenue as a percent (line 3).
** 2022 Estimated Composite tax rate utilized to derive income tax expense is 24.72%.

Supporting Schedules:
N/A

Recap Schedules:
A-1

Note: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE D-1
SUMMARY COST OF CAPITAL
TOTAL COMPANY
ADJUSTED TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

		Adjusted*** End of Test Year 6/30/2022				Projected - Present Rates End Of 12/31/2022				Projected - Present Rates End Of 12/31/2023				
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
Line No.	Invested Capital	Amount	%	Cost Rate	Composite Cost	Amount	%	Cost Rate	Composite Cost	Amount	%	Cost Rate	Composite Cost	Line No.
1.	Long-Term Debt * (a)	$6,315,975	48.07%	3.85%	1.85%	$6,943,975	50.11%	3.92%	1.96%	$7,443,975	51.06%	4.10%	2.09%	1.
2.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	2.
3.	Common Equity (c)	6,822,261	51.93%	10.25%	5.32%	6,912,266	49.89%	10.25%	5.11%	7,134,653	48.94%	10.25%	5.02%	3.
4.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	4.
5.	Total	$ 13,138,236	100.00%		7.17%	$ 13,856,241	100.00%		7.07%	$ 14,578,628	100.00%		7.11%	5.

		Projected - Present Rates End Of 12/31/2024				Projected - Proposed Rates End of 12/31/2023				Projected - Proposed Rates End of 12/31/2024				
		(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	
		Amount	%	Cost Rate	Composite Cost	Amount	%	Cost Rate	Composite Cost	Amount	%	Cost Rate	Composite Cost	
6.	Long-Term Debt * (a)	$7,693,975	50.18%	4.23%	2.12%	$7,493,975	51.17%	4.11%	2.10%	$7,343,975	48.06%	4.28%	2.06%	6.
7.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	7.
8.	Common Equity (c)	7,638,505	49.82%	10.25%	5.11%	7,151,486	48.83%	10.25%	5.01%	7,937,270	51.94%	10.25%	5.32%	8.
9.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	9.
10.	Total	$ 15,332,480	100.00%		7.23%	$ 14,645,461	100.00%		7.11%	$ 15,281,245	100.00%		7.38%	10.

Notes:
* Debt balances exclude unamortized discounts/premiums/debt issuance cost and Palo Verde capital lease obligation.
** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions and excluded in the cost of capital calculation. For the unadjusted Test Year ended June 30, 2022, there was $515,000 short-term debt.
*** See Schedule D-1, page 2 of 2 for pro forma adjustments to Test Year actual period ended June 30,2022.

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE D-1
SUMMARY COST OF CAPITAL
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

		End of Test Year 6/30/2022 - Unadjusted				Proformas to Test Year Ended 6/30/2022					End of Year 6/30/2022 - Adjusted				
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
Line No.	Invested Capital	Amount (d)	% (d)	Cost Rate	Composite Cost (d)	Remove Short-Term Debt **	SERP OCI to Zero***	Derivative OCI to Zero***	Combined Total Adj. Amount	Cost Rate Adj.	Amount	%	Cost Rate	Composite Cost	Line No.
1.	Long-Term Debt * (a)	$ 6,315,975	46.38%	3.85%	1.79%	-	-	-	-	0.00%	$ 6,315,975	48.07%	3.85%	1.85%	1.
2.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	-	-	-	0.00%	-	0.00%	0.00%	0.00%	2.
3.	Common Equity (c)	6,786,040	49.84%	8.70%	4.34%	-	36,221	-	36,221	1.55%	6,822,261	51.93%	10.25%	5.32%	3.
4.	Short-Term Debt ** (a)	515,000	3.78%	1.85%	0.07%	(515,000)	-	-	(515,000)	-1.85%	-	0.00%	0.00%	0.00%	4.
5.	Total	$ 13,617,015	100.00%		6.20%						$ 13,138,236	100.00%		7.17%	5.

Notes:
* Debt balances exclude unamortized discounts/premiums/debt issuance cost and Palo Verde capital lease obligation.
** Under FERC regula ions, short-term debt is utilized as a source of financing on Construc ion Work in Progress, therefore recoverable through AFUDC provisions and excluded from the cost of capital calculation. For the unadjusted Test Year ended June 30, 2022, there was $515,000 short-term debt.
*** SERP OCI removed from balance because no equity or debt issuance was used for the balance.

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4

Recap Schedules:
(d) A-3

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE D-2
COST OF LONG-TERM AND SHORT-TERM DEBT
TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Description of Debt	Test Year End of Year 6/30/22 (A) Outstanding	Test Year End of Year 6/30/22 (B) Annual Interest *	Projected - Present Rates End of Year 12/31/2022 (C) Outstanding	Projected - Present Rates End of Year 12/31/2022 (D) Annual Interest *	Projected - Present Rates End of Year 12/31/2023 (E) Outstanding	Projected - Present Rates End of Year 12/31/2023 (F) Annual Interest *	Projected - Present Rates End of Year 12/31/2024 (G) Outstanding	Projected - Present Rates End of Year 12/31/2024 (H) Annual Interest *	Projected - Proposed Rates End of Year 12/31/2023 **** (I) Outstanding	Projected - Proposed Rates End of Year 12/31/2023 **** (J) Annual Interest *	Projected - Proposed Rates End of Year 12/31/2024 (K) Outstanding	Projected - Proposed Rates End of Year 12/31/2024 (L) Annual Interest *	Line No.
	Long-Term:													
1.	Pollution Control Indebtedness	$ 35,975	$ 500	$ 163,975	$ 1,444	$ 163,975	$ 4,139	$ 163,975	$ 3,983	$ 163,975	$ 4,139	$ 163,975	$ 3,983	1.
2.	Capitalized Lease obligation			-	-	-	-	-	-	-	-	-	-	2.
3.	Other Long-Term Debt - Unsecured Notes	6,280,000	240,998	6,780,000	270,100	7,280,000	299,138	7,530,000	319,712	7,330,000	302,049	7,180,000	308,565	3.
4.	Other	-	1,506	-	797	-	1,594	-	1,859	-	1,594	-	1,859	4.
5.	Total Long-Term (a) **	$ 6,315,975	$ 243,004	$ 6,943,975	$ 272,341	$ 7,443,975	$ 304,870	$ 7,693,975	$ 325,555	$ 7,493,975	$ 307,781	$ 7,343,975	$ 314,408	5.
6.	Cost Rate (a)	3.85%		3 92%		4.10%		4.23%		4.11%		4 28%		6.
	Short-term:													
7.	Commercial Paper	515,000	9,514	-	-	-	-	-	-	-	-	-	-	7.
8.	Total Short-Term (a) (b) ***	$ 515,000	$ 9,514	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	8.
9.	Cost Rate (a)	1.85%		N/A***		N/A***		N/A***		N/A***		N/A***		9.

Notes:
* Including amortization of discount, premium and expense.
** Excludes unamortized discount of ($47,704).
*** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions and excluded from the cost of capital calculation. For the unadjusted Test Year ending 6/30/22, actual short-term debt was $515,000.
**** Proposed Rates for year-end 12/31/2023 includes 1 month of proposed rates, as assumed effective date is 12/1/2023.

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE D-3
COST OF PREFERRED STOCK
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PROJECTED YEARS 2022, 2023 and 2024
(Thousands of Dollars)

		Test Year Ended 6/30/2022			Projected - Present Rates End of Year 12/31/2022			Projected - Present Rates End of Year 12/31/2023			Projected - Present Rates End of Year 12/31/2024			Projected - Projected Rates End of Year 12/31/2023			Projected - Projected Rates End of Year 12/31/2024			
		(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	*(N)*	*(O)*	*(P)*	*(Q)*	*(R)*	
Line No.	Description of Issue	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	*Line No.*
1.	No Outstanding Issues	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	*1.*
2.	Total (a) (b)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	*2.*
3.	Cost Rate (a)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	*3.*

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE D-4
COST OF COMMON EQUITY
TEST YEAR ENDED JUNE 30, 2022

For purposes of this filing, Arizona Public Service Company is proposing a return on common equity of 10.25%.

Supporting Schedules
N/A

Recap Schedules
D-1

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-1
COMPARATIVE BALANCE SHEETS
TOTAL COMPANY
YEAR ENDED JUNE 30, 2022 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 6/30/2022 (A)		Prior Year Ended 12/31/2021 (B)		Prior Year Ended 12/31/2020 (C)	Line No.
	UTILITY PLANT:						
1.	Plant in service and held for future use	$ 23,402,181		$ 22,897,396		$ 21,988,721	1.
2.	Accumulated depreciation and amortization	(8,525,605)		(8,331,220)		(7,935,132)	2.
3.	Net	14,876,576		14,566,176		14,053,589	3.
	Intangible assets, net of accumulated amortization	-		-		-	
5.	Nuclear fuel, net of accumulated amortization	132,696	(a)	106,038	(a)	113,645	5.
6.	Total property, plant and equipment	16,376,105	(a)	16,002,211	(a)	15,106,321	6.
	INVESTMENTS AND OTHER ASSETS:						
7.	Nuclear decommissioning trust	1,076,088		1,294,757		1,138,435	7.
8.	Other special use funds	346,406		358,410		254,509	8.
9.	Assets from risk management activities	111,847		48,302		3,150	9.
10.	Non-Non-Utility Property	7,487		7,487		10,114	10.
11.	Non-Utility Property Depr and Amort	(102)		(90)		(3,640)	11.
12.	Other assets	904		606		3,432	12.
13.	Total investments and other assets	1,542,630		1,709,472		1,406,000	13.
	CURRENT ASSETS:						
14.	Cash and cash equivalents	27,782		9,374		57,310	14.
15.	Customer and other receivables	419,364		390,533		312,643	15.
16.	Accrued unbilled revenues	234,523		133,980		132,197	16.
17.	Allowance for doubtful accounts	(23,147)		(25,354)		(19,782)	17.
18.	Materials and supplies (at average cost)	371,655		349,135		314,745	18.
	Income tax receivable	-		-		-	
	Deferred income taxes	-		-		-	
21.	Other current assets	110,126		102,409		81,539	21.
22.	Total current assets	1,347,895		1,044,886		904,075	22.
	DEFERRED DEBITS:						
23.	Regulatory assets	1,669,520		1,690,574		1,404,830	23.
24.	Operating lease right-of-use assets	866,182		888,207		503,475	24.
25.	Assets for pension and other postretirement benefits	568,515		537,092		495,673	25.
26.	Unamortized Loss on Reacquired Debt	10,227		11,020		12,565	26.
27.	Other	38,714		33,528		32,156	27.
28.	Total deferred debits	3,153,158		3,160,421		2,448,699	28.
29.	TOTAL	$ 22,419,788		$ 21,916,990		$ 19,865,095	29.

Supporting Schedules:
(a) E-5

Recap Schedules:
N/A - See Next Page

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-1
COMPARATIVE BALANCE SHEETS
TOTAL COMPANY
YEAR ENDED JUNE 30, 2022 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 6/30/2022 (A)	Prior Year Ended 12/31/2021 (B)	Prior Year Ended 12/31/2020 (C)	Line No.
	CAPITALIZATION:				
1.	Common stock	$ 178,162	$ 178,162	$ 178,162	1.
2.	Additional paid-in capital	3,171,696	3,021,696	2,871,696	2.
3.	Retained earnings	3,472,403	3,470,235	3,216,954	3.
4.	Accumulated other comprehensive loss	(36,221)	(34,880)	(40,918)	4.
5.	Total shareholder equity (b)	6,786,040	6,635,213	6,225,894	5.
6.	Long-term debt less current maturities	6,448,009	6,453,231	5,963,371	6.
7.	Total capitalization	13,234,049	13,088,444	12,189,265	7.
	CURRENT LIABILITIES:				
8.	Short-term borrowings	515,000	278,700	-	8.
9.	Accounts payable	539,487	492,802	423,082	9.
10.	Accrued taxes	200,403	160,995	157,070	10.
11.	Accrued interest	56,626	56,622	56,322	11.
12.	Customer deposits	41,459	42,293	48,340	12.
13.	Liabilities from risk management activities	4,053	6,084	9,212	13.
14.	Operating lease liabilities - ST	138,408	113,392	89,804	14.
15.	Other current liabilities	159,800	139,484	173,032	15.
16.	Total current liabilities	1,655,236	1,290,372	956,862	16.
	DEFERRED CREDITS AND OTHER:				
17.	Deferred income taxes	2,342,863	2,322,717	2,135,573	17.
18.	Regulatory liabilities	2,597,271	2,713,540	2,561,386	18.
19.	Liability for asset retirements	784,472	767,383	705,083	19.
20.	Liabilities for pension benefits	137,355	138,328	148,943	20.
21.	Liabilities from risk management activities	-	1,394	12,394	21.
22.	Customer advances	336,198	257,151	221,032	22.
23.	Coal mine reclamation	176,936	174,616	170,097	23.
24.	Deferred investment tax credit	184,032	186,570	191,372	24.
25.	Unrecognized tax benefits	37,662	37,424	39,410	25.
26.	Operating lease liabilities - LT	705,305	726,572	372,741	26.
27.	Unamortized Gain on Reacquired Debt	47	69	112	27.
28.	Other	228,362	212,410	160,825	28.
29.	Total deferred credits and other	7,530,503	7,538,174	6,718,968	29.
30.	TOTAL	$ 22,419,788	$ 21,916,990	$ 19,865,095	30.

Supporting Schedules:
N/A - See previous page

Recap Schedules:
(b) A-3

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-2
COMPARATIVE INCOME STATEMENTS
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEARS
(Thousands of dollars, except per share amounts)

Line No.	Description	Test Year Ended 6/30/2022 (b) (A)	Prior Year Ended 12/31/2021 (B)	Prior Year Ended 12/31/2020 (C)	Line No.
1.	OPERATING REVENUES (a)	$ 3,981,825	$ 3,823,903	$ 3,591,984	1.
	OPERATING EXPENSES				
2.	Fuel and purchased power	1,335,138	1,179,143	1,002,959	2.
3.	Operations and maintenance	829,446	818,490	870,209	3.
4.	Depreciation and amortization	703,703	647,034	611,043	4.
5.	Income taxes	115,485	128,940	97,903	5.
6.	Taxes other than income taxes	253,435	261,629	251,065	6.
7.	Total	3,237,207	3,035,236	2,833,179	7.
8.	OPERATING INCOME (a)	744,618	788,667	758,805	8.
	OTHER INCOME (DEDUCTIONS)				
9.	Income taxes	6,122	2,852	9,405	9.
10.	Allowance for equity funds used during construction	44,373	41,737	33,776	10.
11.	Other income	25,759	49,579	56,472	11.
12.	Other expense	(20,096)	(28,551)	(75,242)	12.
13.	Total (a)	56,158	65,617	24,411	13.
14.	Income Before Interest Deductions	800,776	854,284	783,216	14.
	INTEREST EXPENSE				
15.	Interest charges	250,332	243,057	233,718	15.
16.	Allowance for borrowed funds used during construction	(20,970)	(21,052)	(18,530)	16.
17.	Total (a)	229,362	222,005	215,188	17.
18.	NET INCOME (a)	571,414	632,279	568,028	18.
19.	Average Common Shares Outstanding	71,264,947	71,264,947	71,264,947	19.
20.	Earnings Per Share of Average Common Stock Outstanding (a)	$ 8.02	$ 8.87	$ 7.97	20.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-2
(b) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT E-3
COMPARATIVE STATEMENTS OF CHANGES IN FINANCIAL POSITION
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 6/30/2022 (a) (A)	Prior Year Ended 12/31/2021 (a) (B)	Prior Year Ended 12/31/2020 (a) (C)	Line No.
	Cash Flows from Operating Activities:				
1.	Net income	$ 571,414	$ 632,279	$ 568,028	1.
	Items not requiring cash:				
2.	Depreciation and amortization including nuclear fuel	769,598	715,009	682,916	2.
3.	Deferred fuel and purchased power	(219,676)	(256,872)	(93,651)	3.
4.	Deferred fuel and purchased power amortization	130,571	44,557	(12,047)	4.
5.	Allowance for equity funds used during construction	(44,373)	(41,737)	(33,776)	5.
6.	Deferred income taxes	101,698	127,698	35,781	6.
7.	Deferred investment tax credit	(3,688)	(4,802)	(5,096)	7.
	Changes in current assets and liabilities:				
8.	Customer and other receivables	(61,750)	(72,102)	(28,205)	8.
9.	Accrued unbilled revenues	(10,605)	(1,783)	(4,032)	9.
10.	Materials, supplies and fossil fuel	(35,736)	(32,870)	11,624	10.
11.	Other current assets	(25,037)	(20,891)	(1,385)	11.
12.	Accounts payable	57,624	13,132	2,660	12.
13.	Other current liabilities	(14,639)	(38,510)	31,737	13.
14.	Change in long-term regulatory liabilities	(197,749)	117,133	77,160	14.
15.	Change in other long-term assets	1,877	(34,008)	(25,600)	15.
16.	Change in operating lease assets	110,705	115,850	82,174	16.
17.	Change in other long-term liabilities	107,169	(308,604)	(304,964)	17.
18.	Change in operating lease liabilities	(104,690)	(108,216)	(75,162)	18.
19.	Net cash flow provided by operating activities	1,132,713	845,263	908,162	19.
	Cash Flows from Investing Activities:				
20.	Capital expenditures	(1,618,214)	(1,526,916)	(1,300,627)	20.
21.	Contr butions in aid of construction	142,642	105,869	79,852	21.
22.	Allowance for borrowed funds used during construction	(20,970)	(21,052)	(18,530)	22.
23.	Net (Increase) Decrease in Receivables	(213)	(216)	(17,348)	23.
24.	Net Increase (Decrease) in Payables and Accrued Expenses	518	54,156	(27,796)	24.
25.	Proceeds from nuclear decommissioning trust sales and other special use funds	1,825,310	1,720,966	819,518	25.
26.	Investment in nuclear decommissioning trust and other special use funds	(1,829,309)	(1,725,480)	(822,608)	26.
27.	Other	(2,148)	275	(554)	27.
28.	Net cash flow used for investing activities	(1,502,384)	(1,392,398)	(1,288,093)	28.
	Cash Flows from Financing Activities:				
29.	Issuance of long-term debt	446,999	446,999	1,099,722	29.
30.	Repayment of long-term debt	-	-	(465,150)	30.
31.	Short-term borrowings and (repayments) — net	20,000	278,700	-	31.
32.	Short-term debt borrowings under revolving credit facility	-	-	540,000	32.
33.	Short-term debt repayments under revolving credit facility	-	-	(540,000)	33.
34.	Dividends paid on common stock	(381,500)	(376,500)	(357,500)	34.
35.	Equity infusion from Pinnacle West	300,000	150,000	150,000	35.
36.	Net cash flow provided by financing activities	385,499	499,199	427,072	36.
37.	Changes in Cash and Cash Equivalents	15,828	(47,936)	47,141	37.
38.	Cash and Cash Equivalents at Beginning of Year	11,954	57,310	10,169	38.
39.	Cash and Cash Equivalents at End of Year	$ 27,782	$ 9,374	$ 57,310	39.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-5

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-4
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Common Shares (A)	Common Stock (B)	Additional Paid-In Capital (C)	Retained Earnings (D)	Accumulated Other Comprehensive Income (Loss) (E)	Total (F)	Line No.
1.	Balance, December 31, 2019	71,264,947	$ 178,162	$ 2,721,696	$ 3,011,927	$ (35,522)	$ 5,876,263	1.
2.	Equity Infusion from Pinnacle West			150,000			150,000	2.
3.	Net income				568,028		568,028	3.
4.	Accumulated other comprehensive income (loss)					(5,396)	(5,396)	4.
5.	Dividends on common stock				(363,000)		(363,000)	5.
6.	Balance, December 31, 2020	71,264,947	178,162	2,871,696	3,216,955	(40,918)	6,225,895	6.
7.	Equity Infusion from Pinnacle West			150,000			150,000	7.
8.	Net income				632,279		632,279	8.
9.	Accumulated other comprehensive income (loss)					6,038	6,038	9.
10.	Dividends on common stock				(379,000)		(379,000)	10.
11.	Other				1		1	11.
12.	Balance, December 31, 2021	71,264,947	178,162	3,021,696	3,470,235	(34,880)	6,635,213	12.
13.	Equity Infusion from Pinnacle West			150,000			150,000	13.
14.	Net income				194,169		194,169	14.
15.	Accumulated other comprehensive income (loss)					(1,341)	(1,341)	15.
16.	Dividends on common stock				(192,000)		(192,000)	16.
17.	Other				(1)		(1)	17.
18.	Balance, June 30, 2022	71,264,947	$ 178,162	$ 3,171,696	$ 3,472,403	$ (36,221)	$ 6,786,040	18.

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-5
SUMMARY DETAIL OF UTILITY PLANT
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEAR ENDED DECEMBER 31, 2021
(Thousands of Dollars)

Line No.	FERC Account Number	Account Description	Prior Year Ended Bal. 12/31/2021 *(A)*	Net Additions (6 Months) *(B)*	Test Year Ended Bal. 6/30/2022 *(C)*	*Line No.*
		Gross Plant Includible in Rate Base:				
1.	101/106	Plant in Service (a) (b)	$ 22,431,934	$ 511,314	$ 22,943,248	*1.*
2.	101.1	Property Under Capital Lease	199,730	(6,530)	193,200	*2.*
3.	108	Less: Accum. Depreciation-Plant in Service	7,277,028	144,921	7,421,949	*3.*
4.	111	Accum. Amortization-Plant in Service	977,625	44,027	1,021,652	*4.*
5.		Net Plant Includible in Rate Base	14,377,011	315,836	14,692,847	*5.*
6.	120.2-120.5	Nuclear fuel, net of amortization (c)	106,039	26,657	132,696	*6.*
7.	107	Construction Work in Progress (c)	1,210,178	59,964	1,270,142	*7.*
8.	120.1	Nuclear Fuel in Process (c)	119,818	(23,127)	96,691	*8.*
9.		Total Construction Work in Progress (c)	1,329,996	36,837	1,366,833	*9.*
10.	105	Plant Held for Future Use	10,207	-	10,207	*10.*
11.	108	Less: Accum Depreciation Related to Plant Held for Future Use	-	-	-	*11.*
12.		Net Plant held for Future Use	10,207	-	10,207	*12.*
13.	114	Electric Plant Acquisition Adjustment	255,526	-	255,526	*13.*
14.	115	Less: Accum Amortization of Plant Acquisition Adjustment	76,567	5,437	82,004	*14.*
15.		Net Electric Plant Acquisition Adjustment	178,959	(5,437)	173,522	*15.*
16.		Utility Plant - Net (c)	$ 16,002,212	$ 373,893	$ 16,376,105	*16.*

Supporting Schedules:
(a) E-5, page 5 of 5

Recap Schedule:
(b) A-4
(c) E-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-5
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEAR ENDED DECEMBER 31, 2021
(Thousands of Dollars)

Line No.	FERC Account No.	Account Description	Prior Year Ended Bal. 12/31/2021 *(A)*	Net Additions (6 Months) *(B)*	Test Year Ended Bal. 6/30/2022 *(C)*	*Line No.*
		Intangible Plant:				
1.	301	Organization	$ -	$ -	$ -	*1.*
2.	302	Franchises and Consents	3,809	-	3,809	*2.*
3.	303	Miscellaneous Intangible Plant	1,013,284	32,605	1,045,889	*3.*
4.		Total Intangible Plant	$ 1,017,093	$ 32,605	$ 1,049,698	*4.*
		Production Plant:				
		Steam Production Plant:				
5.	310	Land and Land Rights	$ 5,427	$ -	$ 5,427	*5.*
6.	311	Structures and Improvements	232,625	(19)	232,606	*6.*
7.	312	Boiler Plant Equipment	1,540,532	(10,183)	1,530,349	*7.*
8.	314	Turbogenerator Units	226,276	(592)	225,684	*8.*
9.	315	Accessory Electric Equipment	134,337	1,500	135,837	*9.*
10.	316	Miscellaneous Power Plant Equip	104,646	(9,528)	95,118	*10.*
11.	317	Asset Retirement Costs for Steam Production	69,152	-	69,152	*11.*
12.		Total Steam Production Plant	$ 2,312,995	$ (18,822)	$ 2,294,173	*12.*
		Nuclear Production Plant:				
13.	320	Land and Land Rights	$ 4,418	$ -	$ 4,418	*13.*
14.	321	Structures and Improvements	907,414	5,123	912,537	*14.*
15.	322	Reactor Plant Equipment	1,329,409	(1,085)	1,328,324	*15.*
16.	323	Turbogenerator Units	461,530	5,989	467,519	*16.*
17.	324	Accessory Electric Equipment	308,936	268	309,204	*17.*
18.	325	Miscellaneous Power Plant Equip	257,465	2,491	259,956	*18.*
19.	326	Asset Retirement Costs for Nuclear Production	(1,335)	-	(1,335)	*19.*
20.		Total Nuclear Production Plant	$ 3,267,837	$ 12,786	$ 3,280,623	*20.*

Supporting Schedules:
N/A

Recap Schedule:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-5
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEAR ENDED DECEMBER 31, 2021
(Thousands of Dollars)

Line No.	FERC Account No.	Account Description	Prior Year Ended Bal. 12/31/2021 *(A)*	Net Additions (6 Months) *(B)*	Test Year Ended Bal. 6/30/2022 *(C)*	*Line No.*
		Hydraulic Production Plant:				
1.	330	Land and Land Rights	$ -	$ -	$ -	*1.*
2.	331	Structures and Improvements	-	-	-	*2.*
3.	332	Reservoirs, Dams and Waterways	-	-	-	*3.*
4.	333	Water Wheels, Turbines and Generators	-	-	-	*4.*
5.	334	Accessory Electric Equipment	-	-	-	*5.*
6.	335	Miscellaneous Power Plant Equip	-	-	-	*6.*
7.	336	Roads, Railroads and Bridges	-	-	-	*7.*
8.	337	Asset Retirement Costs for Hydraulic Production	-	-	-	*8.*
9.		Total Hydraulic Production Plant	$ -	$ -	$ -	*9.*
		Other Production Plant:				
10.	340	Land and Land Rights	$ 16,108	$ -	$ 16,108	*10.*
11.	341	Structures and Improvements	278,150	8,338	286,488	*11.*
12.	342	Fuel Holders, Producers and Accessories	66,438	1,530	67,968	*12.*
13.	343	Prime Movers	1,086,016	(2,405)	1,083,611	*13.*
14.	344	Generators	1,762,069	13,694	1,775,763	*14.*
15.	345	Accessory Electric Equipment	305,832	9,315	315,147	*15.*
16.	346	Miscellaneous Power Plant Equip	94,376	4,531	98,907	*16.*
17.	347	Asset Retirement Costs for Other Production	29,871	(1)	29,870	*17.*
18.		Total Other Production Plant	$ 3,638,860	$ 35,002	$ 3,673,862	*18.*
19.		Total Production Plant	$ 9,219,692	$ 28,966	$ 9,248,658	*19.*

Supporting Schedules:
N/A

Recap Schedule:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-5
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEAR ENDED DECEMBER 31, 2021
(Thousands of Dollars)

Line No.	FERC Account No.	Account Description	Prior Year Ended Bal. 12/31/2021 *(A)*	Net Additions (6 Months) *(B)*	Test Year Ended Bal. 6/30/2022 *(C)*	*Line No.*
		Transmission Plant				
1.	350	Land and Land Rights	$ 239,031	$ 6,984	$ 246,015	*1.*
2.	352	Structures and Improvements	227,667	3,317	230,984	*2.*
3.	353	Station Equipment	1,385,829	(4,557)	1,381,272	*3.*
4.	354	Towers and Fixtures	191,882	2,884	194,766	*4.*
5.	355	Poles and Fixtures	735,549	8,438	743,987	*5.*
6.	356	Overhead Conductors and Devices	524,419	133,087	657,506	*6.*
7.	357	Underground Conduit	32,422	(237)	32,185	*7.*
8.	358	Underground Conductors and Devices	57,110	6,091	63,201	*8.*
9.		Total Transmission Plant	$ 3,393,909	$ 156,007	$ 3,549,916	*9.*
		Distribution Plant:				
10.	360	Land and Land Rights	$ 83,282	$ 1,031	$ 84,313	*10.*
11.	361	Structures and Improvements	114,845	3,341	118,186	*11.*
12.	362	Station Equipment	836,433	42,756	879,189	*12.*
13.	363	Storage Battery Equipment	1,903	2,350	4,253	*13.*
14.	364	Poles, Towers, and Fixtures	846,701	25,945	872,646	*14.*
15.	365	Overhead Conductors and Devices	449,198	17,434	466,632	*15.*
16.	366	Underground Conduit	811,257	6,568	817,825	*16.*
17.	367	Underground Conductors and Devices	2,301,501	113,585	2,415,086	*17.*
18.	368	Line Transformers	1,070,086	6,085	1,076,171	*18.*
19.	369	Services	539,601	21,313	560,914	*19.*
20.	370	Meters	330,363	4,506	334,869	*20.*
21.	371	Installations on Customers' Premises	47,195	149	47,344	*21.*
22.	373	Street Lighting and Signal Systems	85,035	849	85,884	*22.*
23.		Total Distribution Plant	$ 7,517,400	$ 245,912	$ 7,763,312	*23.*

Supporting Schedules:
N/A

Recap Schedule:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-5
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEAR ENDED DECEMBER 31, 2021
(Thousands of Dollars)

Line No.	FERC Account No.	Account Description	Prior Year Ended Bal. 12/31/2021 *(A)*	Net Additions (6 Months) *(B)*	Test Year Ended Bal. 6/30/2022 *(C)*	*Line No.*
		General Plant				
1.	389	Land and Land Rights	$ 23,117	$ (25)	$ 23,092	*1.*
2.	390	Structures and Improvements	342,395	12,385	354,780	*2.*
3.	391	Office Furniture and Equipment	369,807	13,735	383,542	*3.*
4.	392	Transportation Equipment	42,832	(1,740)	41,092	*4.*
5.	393	Stores Equipment	627	(25)	602	*5.*
6.	394	Tools, Shop and Garage Equipment	60,715	17,222	77,937	*6.*
7.	395	Laboratory Equipment	1,152	-	1,152	*7.*
8.	396	Power Operated Equipment	10,230	(514)	9,716	*8.*
9.	397	Communication Equipment	397,719	6,332	404,051	*9.*
10.	398	Miscellaneous Equipment	35,246	454	35,700	*10.*
11.		Total General Plant	$ 1,283,840	$ 47,824	$ 1,331,664	*11.*
12.		Total Gross Plant Includible in Rate Base (a)	$ 22,431,934	$ 511,314	$ 22,943,248	*12.*

Supporting Schedules:
N/A

Recap Schedule:
(a) E-5, page 1 of 5

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-6
COMPARATIVE DEPARTMENTAL OPEARTING STATEMENTS
TEST YEAR ENDED 6/30/2022 AND PRIOR YEARS

SCHEDULE E-6 DOES NOT APPLY
TO ARIZONA PUBLIC SERVICE COMPANY

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-7
ELECTRIC OPERATING STATISTICS
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEARS

Line No.	Description	Test Year Ended 6/30/2022 (A)	Year Ended 12/31/2021 (B)	Prior Year Ended 12/31/2020 (C)	Line No.
1.	**Billed kWh Sales (thousands)**				1.
2.	Residential	14,311,154	14,266,698	14,730,538	2.
3.	Commercial	13,107,546	12,723,405	12,225,834	3.
4.	Industrial	2,126,917	2,139,181	2,246,170	4.
5.	Irrigation	9,526	9,709	10,280	5.
6.	Public Street and Highway Lighting	106,713	106,868	123,067	6.
7.	Other Sales to Public Authorities	2,024	1,886	1,714	7.
8.	Total Sales to Ultimate Consumers	29,663,880	29,247,747	29,337,603	8.
9.	Sales for Resale - Requirements Customers	-	-	96,199	9.
10.	Sales for Resale - Other Customers	3,986,871	3,850,839	2,992,109	10.
11.	Total Sales for Resale	3,986,871	3,850,839	3,088,308	11.
12.	**Total kWh Sales**	33,650,751	33,098,586	32,425,911	12.
13.	**Average Number of Customers**				13.
14.	Residential	1,190,354	1,177,343	1,150,194	14.
15.	Commercial	136,187	135,503	133,874	15.
16.	Industrial	2,575	2,670	2,875	16.
17.	Irrigation	342	348	356	17.
18.	Public Street and Highway Lighting	1,272	1,265	1,266	18.
19.	Other Sales to Public Authorities	138	136	138	19.
20.	Total Retail Consumers	1,330,868	1,317,265	1,288,703	20.
21.	Sales for Resale - Requirements Customers	-	-	12	21.
22.	**Total Customers**	1,330,868	1,317,265	1,288,715	22.
23.	**Average Billed kWh Use (Annual)**				23.
24.	Residential	12,023	12,118	12,807	24.
25.	Commercial	96,247	93,898	91,323	25.
26.	Industrial	825,987	801,191	781,277	26.
27.	Irrigation	27,854	27,899	28,876	27.
28.	Public Street and Highway Lighting	83,894	84,481	97,209	28.
29.	Other Sales to Public Authorities	14,667	13,868	12,420	29.
30.	Sales for Resale - Requirements Customers	-	-	8,016,583	30.
31.	**Average Annual Revenue per Residential Customer**				31.
32.	Annual Revenue per Customer	1,633.93	1,628.66	1,675.16	32.
33.	Revenue per kWh (Cents)	13.59	13.44	13.08	33.
34.	**Direct Production Expense per kWh Sold (Cents)**	4.48	4.73	4.36	34.
35.	**Direct Transmission Expense per kWh Sold (Cents)**	0.24	0.25	0.26	35.

Supporting Schedules:
N/A

Recap Schedules:
N/A

Please note: Information above includes billed amounts only.

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-8
TAXES CHARGED TO OPERATIONS
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2022 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 6/30/2022 *(A)*	Year Ended 12/31/2021 *(B)*	Prior Year Ended 12/31/2020 *(C)*	*Line No.*
	Federal Taxes:				
1.	Income	$ 12,213	$ (3,014)	$ 56,609	*1.*
2.	F.I.C.A.*	26,309	27,596	26,795	*2.*
3.	Deferred Income Taxes	83,424	110,240	24,833	*3.*
4.	Total	121,946	134,822	108,237	*4.*
	State Taxes:				
5.	Ad Valorem	227,087	233,994	224,253	*5.*
6.	Sales and Use**	39	39	18	*6.*
7.	Income	(169)	(1,555)	(255)	*7.*
8.	Deferred Income Taxes	20,017	23,270	16,716	*8.*
9.	Total	246,974	255,748	240,731	*9.*
10.	Total Taxes	$ 368,920	$ 390,569	$ 348,969	*10.*

Notes:
* Includes payroll related taxes charged by others. These taxes are included in operations and maintenance on C-1, E-2 and F-1.
** Includes local taxes.

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE E-9
NOTES TO FINANCIAL STATEMENTS
TEST YEAR ENDED 6/30/2022 AND PRIOR YEARS

See the attached FERC Form 1 and FERC Form 3-Qs filed with the Federal Energy Regulatory Commission for the period ended:

June 30, 2021. Notes to financial statements are contained on pages 109.1 through 109.34.
December 31, 2021. Notes to financial statements are contained on pages 22 through 33.
June 30, 2022. Notes to financial statements are contained on pages 8 through 17.

Supporting Schedules:
N/A

Recap Schedules:
N/A

APS SCHEDULE E-9
FERC FORM 3-Q

Quarterly Period Ended
June 30, 2021

THIS FILING IS
Document Accession #: 20210826-8032 Filed Date: 08/26/2021

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Arizona Public Service Company	End of 2021/Q2

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: https://forms.ferc.gov/. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____ , we have also reviewed schedules _____of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/overview.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/media/form-1 and https://www.ferc.gov/media/form1-3q.

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

Document Accession #: 20210826-3054 Filed Date: 08/26/2021

IDENTIFICATION

01 Exact Legal Name of Respondent Arizona Public Service Company	02 Year/Period of Report End of 2021/Q2
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 400 North 5th Street, Phoenix, AZ 85004	
05 Name of Contact Person Barbara D. Lockwood	06 Title of Contact Person Senior VP, Public Policy
07 Address of Contact Person *(Street, City, State, Zip Code)* 400 North 5th Street, Phoenix, AZ 85004	

08 Telephone of Contact Person,*Including Area Code* (602) 250-3361	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 08/26/2021

QUARTERLY CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Elizabeth A. Blankenship	03 Signature Elizabeth A. Blankenship	04 Date Signed *(Mo, Da, Yr)* 08/26/2021
02 Title VP Controller & CAO APS/PNW		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	Important Changes During the Quarter	108 109	
2	Comparative Balance Sheet	110 113	
3	Statement of Income for the Quarter	114 117	
4	Statement of Retained Earnings for the Quarter	118 119	
5	Statement of Cash Flows	120 121	
6	Notes to Financial Statements	122 123	
7	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122 (a)(b)	
8	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200 201	
9	Electric Plant In Service and Accum Provision For Depr by Function	208	
10	Transmission Service and Generation Interconnection Study Costs	231	
11	Other Regulatory Assets	232	
12	Other Regulatory Liabilities	278	
13	Elec Operating Revenues (Individual Schedule Lines 300 301)	300 301	
14	Regional Transmission Service Revenues (Account 457.1)	302	
15	Electric Prod, Other Power Supply Exp, Trans and Distrib Exp	324	
16	Electric Customer Accts, Service, Sales, Admin and General Expenses	325	
17	Transmission of Electricity for Others	328 330	
18	Transmission of Electricity by ISO/RTOs	331	
19	Transmission of Electricity by Others	332	
20	Deprec, Depl and Amort of Elec Plant (403,403.1,404,and 405) (except A	338	
21	Amounts Included in ISO/RTO Settlement Statements	397	
22	Monthly Peak Loads and Energy Output	399	
23	Monthly Transmission System Peak Load	400	
24	Monthly ISO/RTO Transmission System Peak Load	400a	

Document Accession #: 20210826-8032 Filed Date: 08/26/2021

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. None.

4. None.

5. Distribution

None.

Transmission

AES 230kV Interconnection at Westwing 230kV Substation

Reason for addition: This will be a generator tie-line to connect the AES Battery Energy Storage Project to the Westwing 230kV Substation.

Size

(a) Voltage Class	230kV AC
(b) Point of Origin	AES 200MW Battery Energy Storage Project
(c) Point of Transmission	Westwing 230kV Substation
(d) Length	Less than 1 mile

Date

(e) Construction Start	2021
(f) In Service	2022

Permitting / Siting Status *An application for a CEC has not yet been filed. APS anticipates filing a CEC application in 2021.*

Hashknife Generation Tie Line Project

Reason for addition: This will be a generator tie-line to connect Hashknife Solar Project to the Cholla 500kV Substation.

Size

(a) Voltage Class	500kV AC
(b) Point of Origin	New substation interconnecting Hashknife Solar Project
(c) Point of Transmission	Cholla 500kV Substation

(d) Length Less than I mile

Date

(e) Construction Start 2021
(f) In Service 2022

Permitting / Siting Status *O11 1/22/2021, in Decision Nos. 77888 and 77889, the Commission granted Invenergy CEC-1 and CEC-2, respectively (Case No. 187). CEC-1 is for the portion of the Project that originates at the Hashknife Solar Project to the point of future ownership change (the Point of Physical Demarcation ("POPD ") near the Cholla Substation property boundary. The companion CEC-2 is for the portion of the Project from the POPD to the point of interconnection at the Cholla Substation. At a future date, Invenergy intends to transfer CEC-2 to APS.*

Runway 230kV Lines

Reason for addition: To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a) Voltage Class 230kV AC
(b) Point of Origin Palm Valley Rudd 230kV line
(c) Point of Transmission Runway Substation
(d) Length Less than I mile per circuit

Date

(e) Construction Start 2019
(f) In Service 2022

Permitting / Siting Status *CEC issued 11/7/2019 (Case No. 183, Decision No. 77469).*

Stratus 230kV Lines

Reason for addition: To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a) Voltage Class 230kV AC
(b) Point of Origin Freedom-Palm Valley & Palm Valley-Rudd 230kV lines
(c) Point of Transmission Stratus Substation

(d) Length Less than 1 mile

Date

(e) Construction Start 2021
(f) In Service 2022

Permitting / Siting Status *CEC issued on 12/22/2003 (Case No. 122, Decision No. 66646, West Valley South Project). Decision No. 73937 amended CEC on 6/27/2013 approving APS s application to extend the CEC term to I2/28/2018 for the first circuit of the Project and to 12/23/2028 for the second circuit and other facilities. Decision No. 77761 amended CEC on 10/2/2020 authorizing two short segments of 230kV doub1e-circuit lines and the Stratus substation. The transmission lines and Stratus substation tie into an existing 230kV transmission line authorized on 12/22/2003 in CEC 122.*

Avery 230kV Lines

Reason for addition: To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a) Voltage Class 230kV AC
(b) Point of Origin Scatter Wash Raceway 230kV line
(c) Point of Transmission Avery 230kV Substation
(d) Length Less than 1 mile

Date

(e) Construction Start 2021
(f) In Service 2022

Permitting / Siting Status *On March 10 2021, APS filed an application to amend CEC Case No. 120 (Decision No. 65997 amended by Decision No. 73824), North Valley Project.*

Relocation of 230kV and 500kV Lines near Avery Substation

Reason for addition: To allow for the development of a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a) Voltage Class 230kV and 500kV AC

(b) Point of Origin	Around Avery 230kV Substation
(c) Point of Transmission	Around TS22 500/230kV substation
(d) Length	Approximately 3.3 miles

Date

(e) Construction Start	2021
(f) In Service	2022

Permitting / Siting Status *On March 10, 2021, APS filed an application Io amend the CEC issued in Case No. 131 (Decision No. 69343).*

6. Contractual Obligations

As of June 30, 2021, our fuel and purchased power commitments have increased from the information provided in our 2020 Federal Energy Regulatory Commission ("FERC") Form 1. The increase is primarily due to new purchased power and energy storage commitments of approximately $624 million. The majority of the changes relate to 2026 and thereafter.

Other than the item described above, there have been no material changes, as of June 30, 2021, outside the normal course of business in contractual obligations from the information provided in our 2020 FERC Form 1. See Note 5 for discussion regarding changes in our short-term and long-term debt obligations. See Note 8 for discussion regarding changes to our contractual obligations related to the Palo Verde sale leaseback transactions.

Credit Facilities

On May 28, 2021, Arizona Public Service ("APS") replaced its two $500 million revolving credit facilities that would have matured in June 2022 and July 2023, with two new $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS’s senior unsecured debt credit ratings and the agreements include a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS’s general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At June 30, 2021, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $495 million of outstanding commercial paper borrowings.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of June 30, 2021, standby letters of credit totaled $0.2 million and would have expired in 2021, subsequently in April of 2021 an extension was effective that reset the expiration dates to 2022. As of June 30, 2021, surety bonds expiring through 2022 totaled $16 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Authorizations

On December 17, 2020, the Arizona Corporation Commission ("ACC") issued a financing order, Decision No. 77853, in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power).

The financing order also approved, subject to specified parameters and procedures, an increase in APS's long-term debt authorization from $5.9 billion to $7.5 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs.

APS's issuances of short-term debt are authorized by the ACC in its Decision No. 77853 and/or by Arizona Revised Statutes Section 40-302.D and the issuances of long-term debt are authorized by the ACC in its Decision No. 77853.

7. Changes in Articles of Incorporation or Amendments to Charter:

None.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

8. Wage Scale Changes

The union and non-union annualized wage scale increases during 2021 through June 30, 2021, were as follows:

	Type of Cost	Number of Increases	Annualized Costs
a.	Union Negotiated	1,199	2,873,795
b.	Non-Union Base Salary Increases	4,030	12,816,871
c.	Special Increases	265	861,318
d.	Promotions	353	3,515,816
Total		5,847	20,067,800

COMMENTS:

a. There were general wage increases for the International Brotherhood of Electrical Workers ("IBEW"), averaging 2.5% during second quarter.
b. The overall non-union employee merit budget was 3.0%. Actual merit adjustments ranged from 0% to 8.0%, based upon an employee's performance and their pay position within the salary range. Merit pay awards were added to base pay.
c. Salary adjustments to base pay are awarded to non-union employees throughout the year in special instances.
d. Promotions were awarded to union and non-union employees due to changes in job functions or grade level changes.

9. Legal Proceedings

I. LITIGATION & ENVIRONMENTAL MATTERS

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high-level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2022.

APS has submitted six claims pursuant to the terms of the August 18, 2014 settlement agreement, for six separate time periods during July 1, 2011 through June 30, 2019. The DOE has approved and paid $99.7 million for these claims (APS's share is $29.0 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers. On November 2, 2020, APS filed its seventh claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). On March 15, 2021, the DOE approved a payment of $12.1 million (APS's share is $3.5 million) and on April 16, 2021, APS received this payment.

Superfund-Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible ("PRPs"). PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, the Environmental Protection Agency ("EPA") advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS during the fourth quarter of 2021. We estimate that our costs related to this investigation and study will be approximately $3 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs

allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on the Four Corners Power Plant ("Four Corners"). EPA required the plant to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plant. In addition, EPA issued a final rule for Regional Haze compliance at the Cholla Power Plant ("Cholla") that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See below for details of the Cholla BART approval.

Four Corners. Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. In addition, APS and El Paso Electric Company ("El Paso") entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4C Acquisition, a wholly owned subsidiary of Pinnacle West ("4CA") purchased the El Paso interest on July 6, 2016. Navajo Transitional Energy Company, LLC ("NTEC") purchased the interest from 4CA on July 3, 2018. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest.

Cholla. In early 2017, EPA approved a final rule containing a revision to Arizona's State Implementation Plan ("SIP") for Cholla that implemented BART requirements for this facility, which did not require the installation

of any new pollution control capital improvements. In conjunction with the closure of Cholla Unit 2 in 2015, APS has committed to ceasing coal combustion within Units 1 and 3 by April 2025. PacifiCorp retired Cholla Unit 4 at the end of 2020. (See "Cholla" below for information regarding future plans for Cholla and details related to the resulting regulatory asset).

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On July 29, 2020, EPA took final action on new regulations establishing revised deadlines for initiating the closure of unlined CCR surface

impoundments by April 11, 2021 at the latest. All APS disposal units subject to these closure requirements were closed as of April 11, 2021.

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's July 29, 2020 final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure (which would allow the continued disposal of CCR within the facility's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025) was submitted to EPA on November 30, 2020 and is currently pending. This application will be subject to public comment and, potentially, judicial review.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $27 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Generating Station ("Navajo Plant") disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021 at the latest (except for those disposable units subject to alternative closure). APS initiated an assessment of corrective measures on January 14, 2019 and expects such assessment will continue through late-2021. As part of this assessment, APS continues to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS will solicit input from the public, host public hearings, and select remedies as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial

position, results of operations or cash flows.

Clean Power Plan/Affordable Clean Energy Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. While the Biden administration has expressed an intent to regulate carbon emissions in this sector more aggressively under the Clean Air Act, we cannot at this time predict the outcome of pending EPA rulemaking proceedings in response to the court's recent ACE decision.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019 filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020 and the EAB denied the environmental group petition on September 30, 2020. On January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. The September 2019 permit remains in effect pending this appeal. The parties are presently engaged in mediation to settle this dispute. We cannot predict the outcome of this appeal proceeding, the ongoing mediation, and, if such appeal is successful, whether that outcome will have a material impact on our financial position, results of operations, or cash flows.

II. REGULATORY MATTERS

COVID-19 Pandemic

Due to the COVID-19 pandemic, APS voluntarily suspended disconnections of customers for nonpayment and waived late payment fees beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and customers were automatically placed on

eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS will continue to waive late payment fees until October 15, 2021. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium (defined below) and the related write-offs of customer delinquent accounts. In February 2021, due to COVID-19, APS delayed the annual reset of the Power Supply Adjustor ("PSA"). Rather than the increase being effective February 2021, the PSA reset was implemented with 50% of the increase effective April 2021 and the remaining 50% increase effective November 2021 (see below for discussion of Environmental Improvement Surcharge ("EIS"), Tax Expense Adjustment Mechanism ("TEAM") Phase II and PSA).

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the Demand Side Management ("DSM") Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the approved amount of $36 million was the result of the Kilowatt hour ("kWh") credit being based on historic consumption, which was different than actual consumption in the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, which was approved by the ACC on June 13, 2021 (see below for discussion of the DSM Adjustor Charge).

In 2020, APS spent more than $15 million to assist customers and local non-profits and community organizations to help with the impact of the COVID-19 pandemic, with $12.4 million of these dollars directly committed to bill assistance programs (the "COVID Customer Support Fund"). The COVID Customer Support Fund was comprised of a series of voluntary commitments of funds that are not recoverable through rates throughout 2020 of approximately $8.8 million. An additional $3.6 million in bill credits for limited income customers was ordered by the ACC in December 2020 of which 50%, up to a maximum of $2.5 million, was committed to be funds that are not recoverable through rates with the remaining being deferred for potential future recovery in rates. Included in the COVID Customer Support Fund were programs that assisted customers that had a delinquency of two or more months with a one-time credit of $100, an expanded credit of $300 for limited income customers, programs to assist extra small and small non-residential customers with a one-time credit of $1,000, and other targeted programs allocated to assist with other COVID-19 needs in support of utility bill assistance. The December 2020 ACC order further assisted delinquent limited income customers with an additional bill credit of up to $250 or their delinquent balance, whichever was less. APS has distributed all funds for all COVID Customer Support Fund programs combined. Beyond the COVID Customer Support Fund, APS has also provided $2.7 million to assist local non-profits and community organizations working to mitigate the impacts of the COVID-19 pandemic.

2019 Retail Rate Case Filing with the Arizona Corporation Commission

In accordance with the requirements of the 2019 rate review order described below, APS filed an application with the ACC on October 31, 2019, seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners Selective Catalytic Reduction ("SCR")

project that is currently the subject of a separate proceeding (see "SCR Cost Recovery" below). It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through TEAM. The proposed total annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of twelve months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	45.3%	4.10%
Common stock equity	54.7%	10.15%
Weighted-average cost of capital		7.41%

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.030168 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- authorization to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- a number of proposed rate and program changes for residential customers, including:
    - a super off-peak period during the winter months for APS's time-of-use with demand rates;
    - additional $1.25 million in funding for APS's limited-income crisis bill program; and
    - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;
- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Generating Station (the "Navajo Plant") (see "Navajo Plant" below).

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC in this rate case. The ACC Staff recommends, among other things, a (i) $89.7 million revenue increase, (ii) average annual customer bill increase of 2.7%, (iii) return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommends, among other things, a (i) $20.8 million revenue

decrease, (ii) average annual customer bill decrease of 0.63%, (iii) return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project. Upon conclusion of APS's rate case and the completion of the deferral mechanisms, approximately $110 million of on-going operating costs related to the Four Corners SCR project and the Ocotillo modernization project will start to be reflected on APS's income statement.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, a (i) $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism ("AEM"), to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition ("CCT") plan related to the closure or future closure of coal-fired generation facilities, of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners Power Plant through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Generating Station, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020 financials.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%.

The hearing concluded on March 3, 2021 and the post-hearing briefing schedule concluded on April 30, 2021. In May 2021, the ACC declined to re-open the evidentiary record in APS's pending rate case to take

additional evidence on topics raised by certain ACC Commissioners, including adjustor cost recovery mechanisms.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in APS's rate case (the "2019 Rate Case ROO"). The 2019 Rate Case ROO recommends, among other things, a (i) $111 million base revenue decrease, (ii) return on equity for original cost rate base of 9.16%, (iii) a 0.15% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.10% reduction to return on equity resulting in an effective fair value return of 0.05%, (iv) nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral and (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Generating Station. These amounts would be recoverable from APS's customers through the Arizona Renewable Energy Standard and Tariff ("RES"). APS expects to file an exception regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO and APS is continuing to evaluate any additional exceptions it may file. The 2019 Rate Case ROO will be discussed at an upcoming ACC open meeting. APS cannot predict the outcome of this proceeding.

2016 Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as an increase of 4.54%).

Other key provisions of the agreement include the following:

- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate

case related to its share of the construction costs associated with installing SCR equipment at Four Corners;

- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the PSA to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as "APS Solar Communities") for utility-owned solar distributed generation ("DG") with the purpose of expanding access to rooftop solar for low- and moderate-income Arizonans, recoverable through the RES, to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
    - a change in the on-peak time of use period from noon-7 p.m. to 3 p.m.-8 p.m. Monday through Friday, excluding holidays;
    - non-grandfathered DG customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
    - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

Through a separate agreement, APS, industry representatives, and solar advocates committed to stand by the 2017 Settlement Agreement and refrain from seeking to undermine it through ballot initiatives, legislation or advocacy at the ACC.

On August 15, 2017, the ACC approved (by a vote of 4-1), the 2017 Settlement Agreement without material modifications. On August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"), which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the ACC Staff to be a complaint filed pursuant to Arizona Revised Statute §40-246 (the "Complaint"). The Complaint was later amended alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The ACC held a hearing on this matter, and the Administrative Law Judge issued a Recommended Opinion and Order recommending that the Complaint be dismissed. On July 3, 2019, the Administrative Law Judge issued an amendment to the Recommended Opinion and Order that incorporated the requirements of the rate review of the 2017 Rate Case Decision (see below discussion regarding the rate review). On July 10, 2019, the ACC adopted the Administrative Law Judge's amended Recommended Opinion and Order along with several ACC Commissioner

amendments and an amendment incorporating the results of the rate review and resolved the Complaint.

See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

ACC Review of APS 2017 Rate Case Decision

On December 24, 2018, certain ACC Commissioners filed a letter stating that because the ACC had received a substantial number of complaints that the rate increase authorized by the 2017 Rate Case Decision was much more than anticipated, they believe there is a possibility that APS is earning more than was authorized by the 2017 Rate Case Decision. Accordingly, the ACC Commissioners requested the ACC Staff to perform a rate review of APS using calendar year 2018 as a test year. The ACC Commissioners also asked the ACC Staff to evaluate APS's efforts to educate its customers regarding the new rates approved in the 2017 Rate Case Decision.

On June 4, 2019, the ACC Staff filed a proposed order regarding the rate review of the 2017 Rate Case Decision. On June 11, 2019, the ACC Commissioners approved the proposed ACC Staff order with amendments. The key provisions of the amended order include the following:

- APS must file a rate case no later than October 31, 2019, using a June 30, 2019 test-year;
- until the conclusion of the rate case being filed no later than October 31, 2019, APS must provide information on customer bills that shows how much a customer would pay on their most economical rate given their actual usage during each month;
- APS customers can switch rate plans during an open enrollment period of six months;
- APS must identify customers whose bills have increased by more than 9% and that are not on the most economical rate and provide such customers with targeted education materials and an opportunity to switch rate plans;
- APS must provide grandfathered net metering customers on legacy demand rates an opportunity to switch to another legacy rate to enable such customers to fully benefit from legacy net metering rates;
- APS must fund and implement a supplemental customer education and outreach program to be developed with and administered by ACC Staff and a third-party consultant; and
- APS must fund and organize, along with the third-party consultant, a stakeholder group to suggest better ways to communicate the impact of changes to adjustor cost recovery mechanisms (see below for discussion on cost recovery mechanisms), including more effective ways to educate customers on rate plans and to reduce energy usage.

APS filed its rate case on October 31, 2019 (see "2019 Retail Rate Case Filing with the Arizona Corporation Commission" above for more information). APS does not believe that the implementation of the other key provisions of the amended order regarding the rate review will have a material impact on its financial position, results of operations or cash flows.

On May 19, 2020, the ACC Staff filed a third-party consultant's report which evaluated the effectiveness of APS's customer outreach and education program related to the 2017 Rate Case Decision. On May 29, 2020, the Chairman of the ACC filed a letter with the ACC in response to this report and is alleging that APS is out of compliance with the 2017 Rate Case Decision and is over-earning. The Chairman proposed that the current rates should be classified as interim rates and customers held harmless if APS's activities have caused the rates set in the 2017 Rate Case Decision to not be just and reasonable. Also, on May 29, 2020, a second commissioner filed a letter with the ACC agreeing with the Chairman's assertions and further asserting that the 2017 Rate Case Decision should be re-opened. On June 18, 2020, at an ACC Open Meeting, the matters raised in these letters were discussed. The ACC did not vote to move forward with any adjustments to APS's current rates. On November 4, 2020, the ACC voted to administratively close this docket.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget. In 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a three-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2020 contained in the RES rules. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan including a waiver of the residential distributed energy requirements for the 2020 implementation year. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 Demand Side Management

Implementation Plan ("DSM Plan").

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2021 contained in the RES rules. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan including a waiver of the residential distributed energy requirements for the 2021 implementation year. As part of the approval, the ACC authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

On May 21, 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its integrated resource planning ("IRP"), and seek cost recovery in a rate process. The adopted rules included substantial changes since the original Recommended Opinion and Order, and thus will require supplemental rulemaking before taking effect. APS cannot predict the outcome of this matter. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS's budget proposal supports existing approved projects and commitments and requests a permanent waiver of the residential and non-residential distributed energy requirements for 2022 contained in the RES rules. The ACC has not yet ruled on the 2022 RES Implementation Plan.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Plan annually for review by and approval of the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its Lost Fixed Cost Recovery ("LFCR") mechanism (see below for discussion of the LFCR).

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan sought a requested budget of $52.6 million and requested a waiver of the Electric Energy Efficiency Standard for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels but kept the overall budget at $52.6 million.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption in the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, which was approved by the ACC on June 13, 2021.

On December 31, 2020, APS filed its 2021 DSM Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Plan that proposed an additional performance incentive for customers participating in the residential energy storage pilot approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Plan.

On April 20, 2021, APS filed a request to extend the June 1, 2021 deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved this request on June 8, 2021.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs.

The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2021 and 2020 (dollars in thousands):

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Beginning balance	$ 175,835	$ 70,137
Deferred fuel and purchased power costs — current period	135,905	26,473
Amounts (charged) refunded to customers	(10,828)	4,815
Ending balance	$ 300,912	$ 101,425

The PSA rate for the PSA year beginning February 1, 2019 was $0.001658 per kWh, as compared to the $0.004555 per kWh for the prior year. This rate was comprised of a forward component of $0.000536 per kWh and a historical component of $0.001122 per kWh. This represented a $0.002897 per kWh decrease compared to 2018. These rates went into effect as filed on February 1, 2019.

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh and consisted of a forward component of $(0.002086) per kWh and a historical component of $0.001630 per kWh. The 2020 PSA rate is a $0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh and consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021 but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA, with 50% of the rate increase effective in April 2021 and the remaining 50% of the increase effective in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh and consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase will be implemented to a rate of $0.003544 per kWh and will consist of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit, which is currently underway, to better understand the factors that contributed to the increase. APS cannot predict the outcome of this audit.

On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA. On December 29, 2020, the ACC Staff filed its report and recommended the storage costs be included in the PSA once the systems are in-service. On January 12, 2021, the ACC approved this application but did not rule on the prudency.

Environmental Improvement Surcharge. The EIS permits APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 for qualified environmental improvements made during the prior calendar year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2021 application requested an increase in the charge to $10.3 million, or $1.5 million over the prior-period charge and it became effective with the first billing cycle in April 2021.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

Transmission Rates, Transmission Cost Adjustor ("TCA") and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the settlement agreement entered into in 2012 regarding APS's rate case ("2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. APS reviews the proposed formula rate filing amounts with the ACC Staff. Any items or adjustments which are not agreed to by APS and the ACC Staff can remain in dispute until settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 7, 2018, APS made a filing to make modifications to its annual transmission formula to provide transmission customers the benefit of the reduced federal corporate income tax rate resulting from the Tax Cuts and Jobs Act ("Tax Act") beginning in its 2018 annual transmission formula rate update filing. These modifications were approved by FERC on May 22, 2018 and reduced APS's transmission rates compared to the rate that would have gone into effect absent these changes. On March 17, 2020, APS made a filing to make further modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Act, as well as for future local, state, and federal statutory tax rate changes. This filing is pending with FERC.

Effective June 1, 2019, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $25.8 million for the 12-month period beginning June 1, 2019 in accordance with the FERC-approved formula. Of this amount, wholesale customer rates increased by $21.1 million and retail customer rates would have increased by approximately $4.7 million. However, since changes in retail transmission charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved TCA balancing account, the retail revenue requirement increased by a total of $4.9 million, resulting in a decrease to residential rates and an increase to commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2019.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the 12-month period beginning June 1, 2020 in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million. However, since changes in retail transmission charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021 in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in retail transmission charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism are currently 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 15, 2018, APS filed its 2018 annual LFCR adjustment, requesting that effective May 1, 2018, the LFCR be adjusted to $60.7 million. On February 6, 2019, the ACC approved the 2018 annual LFCR adjustment to become effective March 1, 2019. On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). On July 10, 2019, the ACC approved APS's 2019 LFCR adjustment as filed, effective with the next billing cycle of July 2019. On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment, thus the previously approved rates continue to remain intact. The $11.8 million will continue to be maintained in the LFCR regulatory asset balancing account and will be included in APS's next LFCR

application filing in accordance with the compliance requirements.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On January 8, 2018, APS filed an application with the ACC that addressed the change in the marginal federal tax rate from 35% to 21% resulting from the Tax Act and reduced rates by $119.1 million annually through an equal cents per kWh credit ("TEAM Phase I"). On February 22, 2018, the ACC approved the reduction of rates through an equal cents per kWh credit. The rate reduction was effective for the first billing cycle in March 2018.

The impact of the TEAM Phase I, over time, is expected to be earnings neutral. However, on a quarterly basis, there is a difference between the timing and amount of the income tax benefit and the reduction in revenues refunded through the TEAM Phase I related to the lower federal income tax rate. The amount of the benefit of the lower federal income tax rate is based on quarterly pre-tax results, while the reduction in revenues refunded through the TEAM Phase I is based on a per kWh sales credit which follows our seasonal kWh sales pattern and is not impacted by earnings of the Company.

On August 13, 2018, APS filed a second request with the ACC that addressed the return of an additional $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 will be recorded as a part of the balancing account and will be addressed for recovery as part of APS's 2019 ACC rate case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit are recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which will provide an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of APS's 2019 pending rate case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM

Phase III monthly bill credit and the offsetting income tax benefit are recognized based upon APS's seasonal kWh sales pattern.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a RCP methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to September 1, 2017, based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh was included in the 2017 Settlement Agreement and became effective on September 1, 2017.

In accordance with the 2017 Rate Case Decision, APS filed its request for a third-year export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. APS's export energy price will remain at 10.5 cents per kWh until October 1, 2021.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not

submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Arizona Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. As part of the 2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

See "2016 Retail Rate Case Filing with the Arizona Corporation Commission" above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC Staff. As part of this docket, Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Burns filed suit against APS and Pinnacle West in the Superior Court of Arizona for Maricopa County in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel.

On August 4, 2017, Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Burns' amended complaint. On March 6, 2018, Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS's 2017 rate case. Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants' motions to dismiss and entered final judgment on January 18, 2019.

On February 13, 2019, Burns filed a notice of appeal. On July 12, 2019, Burns filed his opening brief in the Arizona Court of Appeals. APS filed its answering brief on October 21, 2019. The Arizona Court of Appeals originally granted the request for oral argument; however, on March 31, 2020, the court vacated the date scheduled for oral argument given the COVID-19 pandemic. The court determined that the matter could be submitted without oral argument and has taken the matter under advisement and will issue a decision without oral argument.

Burns' position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. Both APS and the ACC filed responses opposing the motion and asserting that the matter is moot. On March 4, 2021, the Court of Appeals found Burns' motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day. In its March 4, 2021 opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021 requesting that the petition be denied. The grant of review by the Arizona Supreme Court is discretionary. Pinnacle West and APS cannot predict the outcome of this matter.

Information Requests from Arizona Corporation Commissioners

On January 14, 2019, ACC Commissioner Kennedy opened a docket to investigate campaign expenditures and political participation of APS and Pinnacle West. In addition, on February 27, 2019, ACC Commissioners Burns and Dunn opened a new docket and requested documents from APS and Pinnacle West related to ACC elections and charitable contributions related to the ACC. On March 1, 2019, ACC Commissioner Kennedy issued a subpoena to APS seeking several categories of information for both Pinnacle West and APS including political contributions, lobbying expenditures, marketing and advertising expenditures, and contributions made to 501(c)(3) and 501(c)(4) entities, for the years 2013-2018. Pinnacle West and APS voluntarily responded to both sets of requests on March 29, 2019. APS also received and responded to various follow-on requests from ACC Commissioners on these matters. Pinnacle West and APS cannot predict the outcome of these matters. The Company's CEO, Mr. Guldner, appeared at the ACC's January 14, 2020 Open Meeting regarding ACC Commissioners' questions about political spending. Mr. Guldner committed to the ACC that, during his tenure,

Pinnacle West and APS, and any of their affiliated companies, will not participate in ACC campaign elections through financial contributions or in-kind contributions.

Energy Modernization Plan

On January 30, 2018, former ACC Commissioner Tobin proposed the Energy Modernization Plan, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the RES, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics.

On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and held various workshops to incorporate feedback from stakeholders and ACC Commissioners from April 2019 through July 2020. At the March 11-12, 2020 workshop, the ACC Staff committed to filing a final draft of proposed rules by July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear is defined as a clean energy resource. The proposed rules also require 50% of retail energy served be renewable by the end of 2035. A new energy efficiency standard was not included in the proposed rules. APS would be required to obtain approval of its action plan included in its IRP and seek recovery of prudently incurred costs in a rate process. If approved by the ACC Commissioners, the rules would require utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, the ACC Staff proposed changing the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020. On October 14, 2020, the ACC passed one amendment to ACC Staff's final draft energy rules that would have required electric utilities to obtain 35% of peak load (as measured in 2020) by 2030 from DSM resources, including traditional energy efficiency, demand response and other programs aimed at reducing energy usage, peak demand management and load shifting. This standard aligned with the proposed rules' three-year resource planning cycle and allowed recovery of costs through existing mechanisms until the ACC issues a decision in a future rate proceeding. On October 29, 2020, the ACC approved an amendment that would have required electric utilities to reduce their carbon emissions over 2016-2018 levels by 50% by 2032; 75% by 2040; and 100% by 2050. The ACC also approved an amendment that required utilities to install energy storage systems with an aggregate capacity equal to 5% of each utility's 2020 peak demand by 2035, of which 40% must be derived from customer-owned or customer-leased distributed storage. Another approved amendment modified the resource planning process, including requirements for the ACC to approve a utility's load forecast and resource plan, and for a utility to perform an all-source request for information to guide its resource plan. On November 13, 2020, the ACC approved

a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules . In May 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules include a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050 and 95% reduction by December 31, 2060. Since the adopted clean energy rules differ substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures will be required before the rules become effective. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020 to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In March 2021, the ACC Staff requested additional time to prepare its assessment of utility IRPs. The ACC has taken no action on APS's IRP. APS cannot predict the outcome of this matter. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year power purchase agreements with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

On July 16, 2020, FERC issued a final rule revising FERC's regulations implementing PURPA. The final rule went into effect on December 31, 2020. APS is evaluating how the revised regulations may impact its operations.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur and customers will have four months to pay back their deposit and any remaining delinquent amounts. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. ACC stakeholder meetings were held in September 2019, October 2019 and January 2020 regarding the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar threshold (June 1 October 15) for disconnection moratoriums. The ACC held two public comment sessions on the draft rules and will conduct a final vote before the rules become effective. The Summer Disconnection Moratorium will remain in effect until the ACC formalizes the final rules package.

Due to the COVID-19 pandemic, APS voluntarily suspended disconnections of customers for nonpayment and waived late payment fees beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS will continue to waive late payment fees until October 15, 2021. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic. See "COVID-19 Pandemic" above for more information.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. An ACC special open meeting workshop was held on December 3, 2018. No substantive action was taken, but interested parties were asked to submit written comments and respond to a list of questions from ACC Staff. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. Interested parties filed comments to the ACC Staff report and a stakeholder meeting and workshop to discuss the retail electric competition rules was held on July 30,

2019. ACC Commissioners submitted additional questions regarding this matter. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. The ACC held a workshop on February 25-26, 2020 on further consideration and discussion of the retail electric competition rules. During a July 15, 2020 ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC Commissioners are continuing to explore the retail electric competition rules. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019 and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. APS developed a new tool for comparing customers' rate plan options. APS had an independent third party verify that the new rate comparison tool works correctly. In February 2020, APS launched the new online rate comparison tool, which is now available for its customers. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict if any action will be taken by the ACC at this time.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, $24 million of which is being returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. Exceptions to the Recommended Opinion and Order were filed by the parties and intervenors on December 7, 2018. The ACC has not issued a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Retail Rate Case filing with the ACC. On March 18, 2020, the ACC agreed to take administrative notice to include in the pending rate case portions of the record in this prior proceeding that are relevant to the SCRs.

On August 2, 2021, the 2019 Rate Case ROO recommended a disallowance of approximately $399 million of SCR plant investments and $61 million of SCR cost deferrals. The ACC has not issued a decision on this matter, but if the recommendation regarding the Four Corners SCR project in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS would be required to record a write-off related to the SCR cost deferrals. As of June 30, 2021, the SCR cost deferral balance is approximately $75 million net of accumulated deferred income taxes. In addition, if the recommendation regarding the SCR plant investment disallowance in the 2019 Rate Case ROO is adopted and ordered by the ACC, the amount of any loss will be determined based on the value of the SCR plant investment assets at the time the disallowance is probable and estimable and could also be affected by other regulatory and legal considerations. As of June 30, 2021, the value of the SCR plant investments is approximately $320 million, net of accumulated deferred income taxes. If a disallowance of all or a portion of the SCR plant investments is determined to be estimable and probable, or if regulatory recovery of all or a portion of the deferred costs is determined to no longer be probable, it is reasonably possible that APS will recognize a material loss on the SCR investments and cost deferrals. For the period ended June 30, 2021, based on the fact that the 2019 Rate Case ROO is not a final decision and that APS intends to file exceptions to the 2019 Rate Case ROO related to the recommended disallowance of SCR plant investments and cost deferrals, among other factors, APS has not recorded any adjustments to write-off or write-down the SCR plant investments or cost deferrals. The pollution control assets are used and useful and are required to operate Four Corners and APS believes that these SCR investments were prudently incurred. APS cannot predict the final outcome of the decision on this matter nor reasonably estimate the amount of any potential loss.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of Cholla and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020. Cholla Unit 4 was retired on December 24, 2020.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs ($48.9 million as of June 30, 2021), in addition to a return on its investment. In accordance with generally accepted accounting principals ("GAAP"), in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. The 2017 Settlement Agreement also shortened the depreciation lives of Cholla Units 1 and 3 to 2025.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that allows for decommissioning activities to begin after the plant ceased operations.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($67 million as of June 30, 2021) plus a return on the net book value as well as other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset ($17.5 million as of June 30, 2021). APS believes it will be allowed recovery of the net book value, retirement and closure costs, in addition to a return on its investment. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of this interest, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted. On August 2, 2021, the 2019 Rate Case ROO recommended that APS record 15% of the annual amortization of the regulatory asset as a non-operating expense. If the recommendation regarding the Navajo Plant in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS does not expect this to have a material impact on its financial statements.

10. None.

11. (Reserved)

12. N/A

13. Board and Officer Elections, Retirements, Resignations and Changes During 2021:

Directors Note all of the Directors are voted on or reappointed in May.

- Humberto S. Lopez retired from the Board of Directors of APS and Pinnacle West Capital Corporation on May 19, 2021.

Officers Note all of the Officers are re-elected in May.

- On April 21, 2021, Patrick Dinkel, Vice President Strategy and Risk of APS, announced his retirement, effective August 31, 2021.
- On May 19, 2021, Jeffrey B. Guldner was appointed President of APS, effective August 13, 2021. He kept all other titles.
- On May 19, 2021, Daniel T. Froetscher was appointed President and Chief Operating Officer of APS until August 13, 2021.
- On May 19, 2021, Bradley J. Albert was appointed Vice President, Resource Management of APS through May 31, 2021.
- On May 19, 2021, Jacob Tetlow was appointed Executive Vice President, Operations of APS.
- On May 19, 2021, Justin M. Joiner was appointed Vice President, Resource Management of APS, effective upon the start of his employment with APS, which was June 7, 2021.
- On June 23, 2021, Robert E. Smith was appointed Executive Vice President, General Counsel and Chief Development Officer of APS and Pinnacle West.

14. N/A

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101 106, 114)	200 201	23,170,662,263	22,492,195,788
3	Construction Work in Progress (107)	200 201	945,265,580	814,449,488
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		24,115,927,843	23,306,645,276
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200 201	8,113,483,585	7,935,132,087
6	Net Utility Plant (Enter Total of line 4 less 5)		16,002,444,258	15,371,513,189
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202 203	119,678,898	124,637,619
8	Nuclear Fuel Materials and Assemblies Stock Account (120.2)		1,683	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		242,975,332	250,852,003
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202 203	133,863,508	137,206,939
13	Net Nuclear Fuel (Enter Total of lines 7 11 less 12)		228,789,039	238,282,683
14	Net Utility Plant (Enter Total of lines 6 and 13)		16,231,233,297	15,609,795,872
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,457,038	10,114,263
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,366,842	3,639,669
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224 225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228 229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund Federal (127)		0	0
28	Other Special Funds (128)		1,982,544,457	1,892,048,702
29	Special Funds (Non Major Only) (129)		0	0
30	Long Term Portion of Derivative Assets (175)		27,304,824	3,149,731
31	Long Term Portion of Derivative Assets Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18 21 and 23 31)		2,014,939,477	1,901,673,027
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non major Only) (130)		0	0
35	Cash (131)		7,688,492	55,265,017
36	Special Deposits (132 134)		0	0
37	Working Fund (135)		3,966,020	1,746,020
38	Temporary Cash Investments (136)		299,587	299,267
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		282,156,364	254,073,667
41	Other Accounts Receivable (143)		74,844,309	58,546,984
42	(Less) Accum. Prov. for Uncollectible Acct. Credit (144)		22,769,024	19,781,744
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		22,451	22,673
45	Fuel Stock (151)	227	17,668,133	13,378,320
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	342,264,092	316,139,165
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202 203/227	0	0
52	Allowances (158.1 and 158.2)	228 229	7,406,355	6,173,305

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	1,592,326	1,394,570
55	Gas Stored Underground Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2 164.3)		0	0
57	Prepayments (165)		48,567,163	45,330,671
58	Advances for Gas (166 167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		223,917,904	132,196,822
62	Miscellaneous Current and Accrued Assets (174)		36,904,054	36,208,391
63	Derivative Instrument Assets (175)		110,981,811	9,020,263
64	(Less) Long Term Portion of Derivative Instrument Assets (175)		27,304,824	3,149,731
65	Derivative Instrument Assets Hedges (176)		0	0
66	(Less) Long Term Portion of Derivative Instrument Assets Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,105,020,561	904,074,520
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		45,544,739	46,911,224
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,574,496,798	1,404,829,825
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,478,001	818,001
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		460,213	858,791
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	31,211,151	30,479,111
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352 353	0	0
81	Unamortized Loss on Reaquired Debt (189)		11,776,432	12,565,165
82	Accumulated Deferred Income Taxes (190)	234	1,004,515,282	952,240,255
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,671,482,616	2,448,702,372
85	TOTAL ASSETS (lines 14 16, 32, 67, and 84)		22,022,675,951	20,864,245,791

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250 251	178,162,368	178,162,368
3	Preferred Stock Issued (204)	250 251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		2,890,807,686	2,890,807,686
7	Other Paid In Capital (208 211)	253	18,400,365	18,400,365
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	37,511,652	37,511,652
11	Retained Earnings (215, 215.1, 216)	118 119	3,284,988,371	3,216,954,483
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118 119	0	0
13	(Less) Reaquired Capital Stock (217)	250 251	0	0
14	Noncorporate Proprietorship (Non major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	39,832,141	40,918,350
16	Total Proprietary Capital (lines 2 through 15)		6,295,014,997	6,225,894,900
17	LONG TERM DEBT			
18	Bonds (221)	256 257	35,975,000	35,975,000
19	(Less) Reaquired Bonds (222)	256 257	0	0
20	Advances from Associated Companies (223)	256 257	0	0
21	Other Long Term Debt (224)	256 257	5,862,369,918	5,862,533,545
22	Unamortized Premium on Long Term Debt (225)		14,177,760	14,780,963
23	(Less) Unamortized Discount on Long Term Debt Debit (226)		15,410,372	15,899,441
24	Total Long Term Debt (lines 18 through 23)		5,897,112,306	5,897,390,067
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases Noncurrent (227)		738,733,618	518,167,336
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		588,419	745,000
29	Accumulated Provision for Pensions and Benefits (228.3)		196,522,279	199,574,137
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long Term Portion of Derivative Instrument Liabilities		0	12,393,671
33	Long Term Portion of Derivative Instrument Liabilities Hedges		0	0
34	Asset Retirement Obligations (230)		731,990,005	705,082,847
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,667,834,321	1,435,962,991
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		495,000,000	0
38	Accounts Payable (232)		369,849,376	311,662,091
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		108,978,237	111,419,556
41	Customer Deposits (235)		44,418,683	48,339,747
42	Taxes Accrued (236)	262 263	219,531,017	174,684,387
43	Interest Accrued (237)		58,234,116	58,177,415
44	Dividends Declared (238)		0	0
45	Matured Long Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original	08/26/2021	end of 2021/Q2
Document Accession #: 20210826-8012	(2) [ ] A Resubmission	Filed Date: 08/26/2021	

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		55,764	37,059
48	Miscellaneous Current and Accrued Liabilities (242)		128,732,710	172,995,193
49	Obligations Under Capital Leases Current (243)		141,508,485	89,804,495
50	Derivative Instrument Liabilities (244)		1,594,665	21,605,396
51	(Less) Long Term Portion of Derivative Instrument Liabilities		0	12,393,671
52	Derivative Instrument Liabilities Hedges (245)		0	0
53	(Less) Long Term Portion of Derivative Instrument Liabilities Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,567,903,053	976,331,668
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		247,530,973	221,031,992
57	Accumulated Deferred Investment Tax Credits (255)	266 267	187,720,286	191,371,520
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	272,162,436	247,010,705
60	Other Regulatory Liabilities (254)	278	2,678,370,981	2,561,386,227
61	Unamortized Gain on Reaquired Debt (257)		90,214	111,866
62	Accum. Deferred Income Taxes Accel. Amort.(281)	272 277	0	0
63	Accum. Deferred Income Taxes Other Property (282)		2,519,807,583	2,477,515,467
64	Accum. Deferred Income Taxes Other (283)		689,128,801	630,238,388
65	Total Deferred Credits (lines 56 through 64)		6,594,811,274	6,328,666,165
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		22,022,675,951	20,864,245,791

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300 301	1,696,733,850	1,591,937,368	996,693,029	931,527,566
3	Operating Expenses					
4	Operation Expenses (401)	320 323	754,866,649	728,355,240	412,037,889	389,555,735
5	Maintenance Expenses (402)	320 323	111,470,542	101,689,380	55,031,040	51,259,335
6	Depreciation Expense (403)	336 337	264,648,320	254,309,628	132,868,632	127,681,995
7	Depreciation Expense for Asset Retirement Costs (403.1)	336 337	2,458,460	2,836,137	1,311,498	1,234,723
8	Amort. & Depl. of Utility Plant (404 405)	336 337	48,585,643	46,181,429	23,462,178	21,598,998
9	Amort. of Utility Plant Acq. Adj. (406)	336 337	5,436,722	5,436,722	2,718,361	2,718,361
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		15,670,298	15,559,340	8,003,895	7,978,770
13	(Less) Regulatory Credits (407.4)		22,180,345	19,429,844	10,780,078	9,565,062
14	Taxes Other Than Income Taxes (408.1)	262 263	133,346,758	126,702,440	66,667,906	62,955,814
15	Income Taxes Federal (409.1)	262 263	27,131,066	10,985,900	23,551,824	10,051,763
16	Other (409.1)	262 263	395,725	3,749,751	49,007	357,335
17	Provision for Deferred Income Taxes (410.1)	234, 272 277	107,823,220	221,793,946	103,242,787	165,509,395
18	(Less) Provision for Deferred Income Taxes Cr. (411.1)	234, 272 277	83,675,631	205,605,950	76,631,338	130,943,599
19	Investment Tax Credit Adj. Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		13,613	12,800	7,614	7,146
23	Losses from Disposition of Allowances (411.9)		13,983	16,324	7,356	6,534
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,365,186,347	1,285,068,141	741,435,329	699,678,281
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		331,547,503	306,869,227	255,257,700	231,849,285

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
1,696,733,850	1,591,937,368					2
						3
754,866,649	728,355,240					4
111,470,542	101,689,380					5
264,648,320	254,309,628					6
2,458,460	2,836,137					7
48,585,643	46,181,429					8
5,436,722	5,436,722					9
						10
						11
15,670,298	15,559,340					12
22,180,345	19,429,844					13
133,346,758	126,702,440					14
27,131,066	10,985,900					15
395,725	3,749,751					16
107,823,220	221,793,946					17
83,675,631	205,605,950					18
						19
						20
						21
13,613	12,800					22
13,983	16,324					23
						24
1,365,186,347	1,285,068,141					25
331,547,503	306,869,227					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		331,547,503	306,869,227	255,257,700	231,849,285
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,259,302	633,521	1,019,251	334,885
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,211,931	447,648	1,055,109	146,934
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		37,195	39,121	19,475	19,475
35	Nonoperating Rental Income (418)		37,525	6,486	36,537	949
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		2,527,551	4,524,089	1,046,625	2,182,710
38	Allowance for Other Funds Used During Construction (419.1)		19,196,967	16,507,846	9,989,590	8,811,136
39	Miscellaneous Nonoperating Income (421)		123,930,006	232,007,251	73,396,746	114,139,439
40	Gain on Disposition of Property (421.1)		4,811,904	1,600,889	3,754,612	875,286
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		150,514,129	254,793,313	88,168,777	126,176,098
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		6,236,971	1,066,482	3,037,400	545,277
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,518,853	5,732,463	52,989	2,888,176
46	Life Insurance (426.2)					
47	Penalties (426.3)		35	5,112	35	
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,378,189	1,277,694	700,371	585,694
49	Other Deductions (426.5)		108,327,247	216,326,547	66,512,273	105,280,495
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		117,461,295	224,408,298	70,197,090	109,299,642
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262 263	279,604	273,043	142,565	135,806
53	Income Taxes Federal (409.2)	262 263	3,703,823	3,707,941	1,940,015	2,918,708
54	Income Taxes Other (409.2)	262 263	917,161	1,014,410	494,689	756,585
55	Provision for Deferred Inc. Taxes (410.2)	234, 272 277	39,579	765,652	33,480	65,371
56	(Less) Provision for Deferred Income Taxes Cr. (411.2)	234, 272 277	1,024,900	1,720,286	866,964	1,615,921
57	Investment Tax Credit Adj. Net (411.5)					
58	(Less) Investment Tax Credits (420)		3,651,233	3,386,231	3,121,870	2,921,014
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52 58)		264,034	654,529	1,378,085	660,465
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		32,788,800	29,730,486	19,349,772	17,536,921
61	Interest Charges					
62	Interest on Long Term Debt (427)		113,841,814	103,386,474	56,898,568	52,310,561
63	Amort. of Debt Disc. and Expense (428)		1,988,206	1,813,597	993,007	915,123
64	Amortization of Loss on Reaquired Debt (428.1)		838,379	790,398	412,306	395,199
65	(Less) Amort. of Premium on Debt Credit (429)		603,203	156,383	301,601	78,192
66	(Less) Amortization of Gain on Reaquired Debt Credit (429.1)		21,652	21,652	10,826	10,826
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		3,451,618	7,148,930	2,070,930	3,483,019
69	(Less) Allowance for Borrowed Funds Used During Construction Cr. (432)		10,192,747	8,824,544	5,199,092	4,748,586
70	Net Interest Charges (Total of lines 62 thru 69)		109,302,415	104,136,820	54,863,292	52,266,298
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		255,033,888	232,462,893	219,744,180	197,119,908
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes Federal and Other (409.3)	262 263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		255,033,888	232,462,893	219,744,180	197,119,908

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance Beginning of Period		3,216,954,483	3,011,926,265
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		255,033,888	232,462,893
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared Preferred Stock (Acct. 437)			
30	Dividends Declared Common Stock (Account 438)			
31		234	187,000,000	(176,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared Common Stock (Acct. 438)		187,000,000	(176,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance End of Period (Total 1,9,15,16,22,29,36,37)		3,284,988,371	3,068,389,158
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,284,988,371	3,068,389,158
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	255,033,888	232,462,893
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	267,108,674	257,147,940
5	Amortization of	81,372,126	84,359,628
6			
7	Deferred Fuel and Purchased Power	125,077,849	31,287,956
8	Deferred Income Taxes (Net)	23,162,268	15,233,362
9	Investment Tax Credit Adjustment (Net)	3,651,233	3,386,231
10	Net (Increase) Decrease in Receivables	133,684,933	62,589,845
11	Net (Increase) Decrease in Inventory	30,216,985	11,083,460
12	Net (Increase) Decrease in Allowances Inventory	1,233,050	788,590
13	Net Increase (Decrease) in Payables and Accrued Expenses	63,750,894	20,162,995
14	Net (Increase) Decrease in Other Regulatory Assets	22,135,078	12,166,764
15	Net Increase (Decrease) in Other Regulatory Liabilities	58,742,456	35,056,035
16	(Less) Allowance for Other Funds Used During Construction	19,196,967	16,507,846
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
19	Other Current Assets	3,888,641	1,379,916
20	Other Current Liabilities	17,996,328	20,182,348
21	Other Long Term Assets/Liabilities Net	124,136,210	70,015,160
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	303,945,688	367,089,587
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	648,601,134	588,394,862
27	Gross Additions to Nuclear Fuel	24,472,553	36,154,725
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	10,192,747	8,824,544
31	Other (provide details in footnote):		
32	Contributions in Aid of Construction	31,533,000	48,708,000
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	651,733,434	584,666,131
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Proceeds from Trust and Other Special Use Funds Sales (a)	587,841,774	391,859,245
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Investment in Trust and Other Special Use Fund Sales (a)	588,982,273	392,999,745
49	Net (Increase) Decrease in Receivables	571,331	17,412,622
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	7,986,223	53,482,231
53	Other (provide details in footnote):		
54			
55	Investments and Other Assets	2,986,932	168,884
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	657,301,893	656,870,368
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long Term Debt (b)		591,936,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short Term Debt (c)	495,000,000	219,900,000
67	Other (provide details in footnote):		
68	Short term debt borrowings under revolving credit facility		540,000,000
69	Short term debt repayments under revolving credit facility		540,000,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	495,000,000	811,836,000
71			
72	Payments for Retirement of:		
73	Long term Debt (b)		350,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	187,000,000	176,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	308,000,000	285,836,000
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	45,356,205	3,944,781
87			
88	Cash and Cash Equivalents at Beginning of Period	57,310,304	10,169,183
89			
90	Cash and Cash Equivalents at End of period	11,954,099	6,224,402

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

Schedule Page: 120 Line No.: 19 Column: b

Prepaids	$ (3,236,492)
Other	(917,453)
Risk Management	265,304
	$ (3,888,641)

Schedule Page: 120 Line No.: 19 Column: c

Prepaids	$ (8,450,667)
Other	(151,279)
Risk Management	(91,200)
Income Tax Receivable	7,313,230
	$ (1,379,916)

Schedule Page: 120 Line No.: 20 Column: b

Accrued Taxes	$ 44,438,615
Operating Leases	22,066,543
SCE Right of Way	3,490,500
Unbilled Revenue	1,690,691
Software License Agreements	1,509,470
Uncertain Tax Position	408,015
Interest Accrued	56,702
Other	(166,248)
Customer Deposits	(3,921,064)
Employee Benefits	(4,063,714)
Exchange	(6,611,665)
Payroll Accrual	(8,246,449)
Four Corners Take or Pay	(8,460,860)
Arizona Attorney General Settlement	(24,194,208)
	$ 17,996,328

Schedule Page: 120 Line No.: 20 Column: c

Customer Deposits	$ (15,775,174)
Payroll Accrual	(13,391,632)
SCE Right of Way	(9,370,156)
Four Corners Take or Pay	(9,084,472)
Fossil Tail Costs	(2,323,329)
SunEdison Line of Credit	(2,000,000)
Software License Agreements	(1,225,833)
Exchange	(439,044)
Other	267,585
Interest Accrued	730,066
Unbilled Revenue	1,192,270
Employee Benefits	3,028,215
Operating Leases	13,657,885
Accrued Taxes	14,551,271
	$ (20,182,348)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

Schedule Page: 120 Line No.: 21 Column: b

Decommissioning Trust	$ (83,512,526)
Postretirement assets	(52,013,302)
Utility Plant (Removal Costs)	(40,640,848)
Long Term Operating Leases	(30,996,492)
Asset retirement obligations expenditures	(3,174,000)
Pension and other benefits	(978,000)
Coal Reclamation Escrow	(54,728)
Community Coal Transition	100,000
Carbon Allowance	1,356,527
Software License Agreement	1,509,470
Active Union Medical Trust	1,923,249
Coal Reclamation	2,259,423
Other Long-Term Assets/Liabilities Net	2,896,628
Information Systems Maintenance	3,301,904
Retention Accrual	3,848,039
Interconnection Study	8,782,704
Customer advances for construction	26,498,981
Operating Lease - Right of Use Assets	34,756,761
	$(124,136,210)

Schedule Page: 120 Line No.: 21 Column: c

Operating Lease - Right of Use Assets	$ (420,504,944)
Utility Plant (Removal Costs)	(24,928,409)
Pension and other benefits	(19,142,000)
Postretirement assets	(14,283,681)
Decommissioning Trust	(12,117,290)
Active Union Medical Trust	(7,275,108)
Customer advances for construction	(1,757,902)
Coal Reclamation Escrow	(962,698)
Information Systems Maintenance	2,188,950
Coal Reclamation	2,200,952
Other Long-Term Assets/Liabilities Net	63,599,261
Long Term Operating Leases	362,967,709
	$ (70,015,160)

Schedule Page: 120 Line No.: 55 Column: b

Restricted Cash Investments	$ 2,826,265
Other	1,121,633
Post-Employment Benefits	(960,966)
	$ 2,986,932

Schedule Page: 120 Line No.: 55 Column: c

Post-Employment Benefits	$ (189,185)
Restricted Cash Investments	(11,454)
Other	31,755

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

$ (168,884)

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8032 Filed Date: 08/26/2021

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

1. Other Comprehensive Basis of Accounting

The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). The primary differences in the accompanying FERC financial statements as compared to GAAP include presenting certain decommissioning and reclamation activities, deferred tax assets and liabilities, regulatory assets and liabilities and risk management assets and liabilities on a gross versus net basis; presenting cost of removal liabilities in accumulated provision for depreciation; presenting tax liabilities related to uncertain tax positions as deferred income tax liabilities; presenting intangible assets in net utility plant; deconsolidating certain Variable Interest Entities ("VIE") and presenting debt issuance costs in deferred debits rather than as a reduction of long-term debt. Additionally, the accompanying FERC financial statements do not separately present the current portion of such items as long-term debt, Asset Retirement Obligations ("ARO") and regulatory assets and liabilities as required by GAAP.

Arizona Public Service's ("APS") notes to financial statements have been combined with Pinnacle West Capital Corporation's financial statements and are prepared in accordance with GAAP; accordingly, certain footnotes are not reflective of APS's financial statements contained herein.

2. Summary of Significant Accounting Policies

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Our unaudited financial statements reflect all adjustments (consisting only of normal recurring adjustments except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations and cash flows for the periods presented. These statements and notes should be read in conjunction with the financial statements and related notes included in our 2020 FERC Form 1.

Allowance for Funds Used During Construction ("AFUDC")

On June 30, 2020, the United States Federal Energy Regulatory Commission ("FERC") issued an order granting a waiver request related to the existing Allowance for Funds Used During Construction ("AFUDC") rate calculation beginning March 1, 2020 through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. The order provides a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS has adopted this simplified approach to computing the AFUDC

composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and has left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacts the AFUDC composite rate in both 2020 and 2021 but does not impact prior years. Furthermore, the change in the composite rate calculation does not impact our accounting treatment for these costs. The change will not have a material impact on our financial statements. See Note 2 in our 2020 Form 1 for information on the accounting treatment for AFUDC.

Cash and Cash Equivalents

We consider all highly liquid investments with a remaining maturity of three months or less at acquisition to be cash equivalents.

The following table summarizes supplemental APS cash flow information (dollars in thousands):

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ 3,317	$
Interest, net of amounts capitalized	107,044	100,991
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 105,515	$ 87,815
Dividends accrued but not yet paid	93,500	88,000

Subsequent Events

Management evaluates events or transactions that occur after the balance sheet date, but before the financial statements are issued or available to be issued for potential recognition or disclosures in the financial statements as required by GAAP. We have evaluated subsequent events for recognition in the financial statements through August 5, 2021, which is the date the financial statements, prepared in accordance with GAAP were issued. Management updated such evaluation for disclosure purposes through August 26, 2021. The accompanying statements contain all adjustments and disclosures necessary for fair presentation.

3. Quarterly Fluctuations

Significant seasonal fluctuations in our revenues are due to the effects of seasonal temperature variations on energy consumption, timing of maintenance on electric generating units, and other factors. For these reasons, amounts reported in interim periods are not necessarily indicative of amounts expected for the respective annual period.

4. Revenue

Sources of Revenue

The following table provides detail of revenue disaggregated by revenue sources (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Retail Electric Revenue				
Residential	$ 531,717	$ 515,128	$ 872,555	$ 840,201
Non-Residential	420,995	381,121	735,778	684,472
Wholesale Energy Sales	19,229	18,703	41,698	32,468
Transmission Services for Others	22,575	14,815	41,558	30,912
Other Sources	2,177	1,761	5,145	3,884
Total operating revenues	$ 996,693	$ 931,528	$1,696,734	$1,591,937

Retail Electric Revenue. Retail electric revenue is generated by the sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the Arizona Corporation Commission ("ACC") and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 15 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms.

Wholesale Energy Sales and Transmission Services for Others. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities primarily consist of managing fuel and purchased power risks in connection with the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

In the electricity business, some contracts to purchase energy are settled by netting against other contracts to sell electricity. This is referred to as a book-out, and usually occurs in contracts that have the same terms (product type, quantities, and delivery points) and for which power does not flow. We report these book-outs on a gross basis, presenting both wholesale revenues, fuel and purchased power costs.

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail

customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the three and six months ended June 30, 2021 were $977 million and $1,663 million, respectively and for the three and six months ended June 30, 2020 were $917 million and $1,563 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the three and six months ended June 30, 2021 our revenues that do not qualify as revenue from contracts with customers were $20 million and $34 million, respectively, and for the three and six months ended June 30, 2020 were $15 million and $29 million, respectively. This relates primarily to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 6 for a discussion of our regulatory cost recovery mechanisms.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Comparative Balance Sheets as of June 30, 2021 or December 31, 2020.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success.

On March 13, 2020, due to the COVID-19 pandemic we voluntarily suspended disconnections of customers for nonpayment. The suspension of customer disconnections was extended from March 13, 2020 through December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and certain customers with past due balances were placed on eight-month payment arrangements. During this time our disconnection policies were also impacted by the Summer Disconnection Moratorium. These circumstances and the on-going COVID-19 pandemic have impacted our allowance for doubtful accounts, including our write-off factor. We continue to monitor the impacts of COVID-19, our disconnection policies, payment arrangements, among other considerations impacting our estimated write-off factor and allowance for doubtful accounts. See Note 6 for additional details.

The following table provides a rollforward of the allowance for doubtful accounts (dollars in thousands):

	June 30, 2021	December 31, 2020
Allowance for doubtful accounts, balance at beginning of period	$ 19,782	$ 8,171
Bad debt expense	10,048	20,633
Actual write-offs	(7,061)	(9,022)
Allowance for doubtful accounts, balance at end of period	$ 22,769	$ 19,782

5. Long-Term Debt and Liquidity Matters

APS maintains committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

On May 28, 2021, APS replaced its two $500 million revolving credit facilities that would have matured in June 2022 and July 2023, with two new $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings and the agreements include a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At June 30, 2021, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $495 million of outstanding commercial paper borrowings.

On December 17, 2020, the Arizona Corporation Commission ("ACC") issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power) and a long-term debt authorization of $7.5 billion.

See "Financial Assurances" in Note 10 for a discussion of other outstanding letters of credit.

Debt Fair Value

Our long-term debt fair value estimates are classified within Level 2 of the fair value hierarchy. The following table presents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of June 30, 2021		As of December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total	$ 5,897,112	$ 6,779,354	$ 5,897,390	$ 7,136,324

6. Regulatory Matters

COVID-19 Pandemic

Due to the COVID-19 pandemic, APS voluntarily suspended disconnections of customers for nonpayment and waived late payment fees beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS will continue to waive late payment fees until October 15, 2021. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium (defined below) and the related write-offs of customer delinquent accounts. In February 2021, due to COVID-19 APS delayed the annual reset of the Power Supply Adjustor ("PSA"). Rather than the increase being effective February 2021, the PSA reset was implemented with 50% of the increase effective April 2021 and the remaining 50% increase effective November 2021 (see below for discussion of EIS, TEAM Phase II and PSA).

On April 17, 2020 APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the Demand Side Management (“DSM”) Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the approved amount of $36 million was the result of the kilowatt hour ("kWh") credit being based on historic consumption, which was different than actual consumption in the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, which was approved by the ACC on June 13, 2021 (see below for discussion of the DSM Adjustor Charge).

In 2020, APS spent more than $15 million to assist customers and local non-profits and community organizations to help with the impact of the COVID-19 pandemic, with $12.4 million of these dollars directly committed to bill assistance programs (the “COVID Customer Support Fund”). The COVID Customer Support Fund was comprised of a series of voluntary commitments of funds that are not recoverable through rates throughout 2020 of approximately $8.8 million. An additional $3.6 million in bill credits for limited income customers was ordered by the ACC in December 2020 of which 50%, up to a maximum of $2.5 million, was committed to be funds that are not recoverable through rates with the remaining being deferred for potential future recovery in rates. Included in the COVID Customer Support Fund were programs that assisted customers that had a delinquency of two or more months with a one-time credit of $100, an expanded credit of $300 for limited income customers, programs to assist extra small and small non-residential customers with a one-time credit of $1,000, and other

targeted programs allocated to assist with other COVID-19 needs in support of utility bill assistance. The December 2020 ACC order further assisted delinquent limited income customers with an additional bill credit of up to $250 or their delinquent balance, whichever was less. APS has distributed all funds for all COVID Customer Support Fund programs combined. Beyond the COVID Customer Support Fund, APS has also provided $2.7 million to assist local non-profits and community organizations working to mitigate the impacts of the COVID-19 pandemic.

2019 Retail Rate Case Filing with the Arizona Corporation Commission

In accordance with the requirements of the 2019 rate review order described below, APS filed an application with the ACC on October 31, 2019 seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project that is currently the subject of a separate proceeding (see "SCR Cost Recovery" below). It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the Tax Expense Adjustment Mechanism ("TEAM"). The proposed total annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of twelve months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	45.3%	4.10%
Common stock equity	54.7%	10.15%
Weighted-average cost of capital		7.41%

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.030168 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- authorization to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- a number of proposed rate and program changes for residential customers, including:
    - a super off-peak period during the winter months for APS's time-of-use with demand rates;
    - additional $1.25 million in funding for APS's limited-income crisis bill program; and
    - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;

- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Generating Station (the "Navajo Plant") (see "Navajo Plant" below).

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC in this rate case. The ACC Staff recommends, among other things, a (i) $89.7 million revenue increase, (ii) average annual customer bill increase of 2.7%, (iii) return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommends, among other things, a (i) $20.8 million revenue decrease, (ii) average annual customer bill decrease of 0.63%, (iii) return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project. Upon conclusion of APS's rate case and the completion of the deferral mechanisms, approximately $110 million of on-going operating costs related to the Four Corners SCR project and the Ocotillo modernization project will start to be reflected on APS's income statement.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, a (i) $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism ("AEM"), to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition ("CCT") plan related to the closure or future closure of coal-fired generation facilities, of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners Power Plant through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would

primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Generating Station, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020 financials.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%.

The hearing concluded on March 3, 2021 and the post-hearing briefing schedule concluded on April 30, 2021. In May 2021, the ACC declined to re-open the evidentiary record in APS's pending rate case to take additional evidence on topics raised by certain ACC Commissioners, including adjustor cost recovery mechanisms.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order ("ROO") in APS's rate case (the "2019 Rate Case ROO"). The 2019 Rate Case ROO recommends, among other things, a (i) $111 million base revenue decrease, (ii) return on equity for original cost rate base of 9.16%, (iii) a 0.15% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.10% reduction to return on equity resulting in an effective fair value return of 0.05%, (iv) nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral and (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Generating Station. These amounts would be recoverable from APS's customers through the RES. APS expects to file an exception regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO and APS is continuing to evaluate any additional exceptions it may file. The 2019 Rate Case ROO will be discussed at an upcoming ACC open meeting. APS cannot predict the outcome of this proceeding.

2016 Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable

to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as an increase of 4.54%).

Other key provisions of the agreement include the following:

- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing SCR equipment at the Four Corners Power Plant ("Four Corners");
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the Power Supply Adjustor ("PSA") to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as "APS Solar Communities") for utility-owned solar distributed generation with the purpose of expanding access to rooftop solar for low and moderate income Arizonans, recoverable through the Arizona Renewable Energy Standard and Tariff ("RES"), to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
    - a change in the on-peak time of use period from noon-7 p.m. to 3 p.m.-8 p.m. Monday through Friday, excluding holidays;
    - non-grandfathered distributed generation ("DG") customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
    - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

Through a separate agreement, APS, industry representatives, and solar advocates committed to stand by the 2017 Settlement Agreement and refrain from seeking to undermine it through ballot initiatives, legislation or advocacy at the ACC.

On August 15, 2017, the ACC approved (by a vote of 4-1) the 2017 Settlement Agreement without material modifications. On August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"), which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the ACC Staff to be a complaint filed pursuant to Arizona Revised Statute §40-246 (the "Complaint"). The Complaint was later amended alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The ACC held a hearing on this matter, and the Administrative Law Judge issued a Recommended Opinion and Order recommending that the Complaint be dismissed. On July 3, 2019, the Administrative Law Judge issued an amendment to the Recommended Opinion and Order that incorporated the requirements of the rate review of the 2017 Rate Case Decision (see below discussion regarding the rate review). On July 10, 2019, the ACC adopted the Administrative Law Judge's amended Recommended Opinion and Order along with several ACC Commissioner amendments and an amendment incorporating the results of the rate review and resolved the Complaint.

See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

ACC Review of APS 2017 Rate Case Decision

On December 24, 2018, certain ACC Commissioners filed a letter stating that because the ACC had received a substantial number of complaints that the rate increase authorized by the 2017 Rate Case Decision was much more than anticipated, they believe there is a possibility that APS is earning more than was authorized by the 2017 Rate Case Decision. Accordingly, the ACC Commissioners requested the ACC Staff to perform a rate review of APS using calendar year 2018 as a test year. The ACC Commissioners also asked the ACC Staff to evaluate APS's efforts to educate its customers regarding the new rates approved in the 2017 Rate Case Decision.

On June 4, 2019, the ACC Staff filed a proposed order regarding the rate review of the 2017 Rate Case Decision. On June 11, 2019, the ACC Commissioners approved the proposed ACC Staff order with amendments. The key provisions of the amended order include the following:

- APS must file a rate case no later than October 31, 2019, using a June 30, 2019 test year;
- until the conclusion of the rate case being filed no later than October 31, 2019, APS must provide information on customer bills that shows how much a customer would pay on their most economical rate given their actual usage during each month;
- APS customers can switch rate plans during an open enrollment period of six months;
- APS must identify customers whose bills have increased by more than 9% and that are not on the most economical rate and provide such customers with targeted education materials and an opportunity to switch rate plans;
- APS must provide grandfathered net metering customers on legacy demand rates an opportunity to

switch to another legacy rate to enable such customers to fully benefit from legacy net metering rates;
- APS must fund and implement a supplemental customer education and outreach program to be developed with and administered by ACC Staff and a third-party consultant; and
- APS must fund and organize, along with the third-party consultant, a stakeholder group to suggest better ways to communicate the impact of changes to adjustor cost recovery mechanisms (see below for discussion on cost recovery mechanisms), including more effective ways to educate customers on rate plans and to reduce energy usage.

APS filed its rate case on October 31, 2019 (see "2019 Retail Rate Case Filing with the Arizona Corporation Commission" above for more information). APS does not believe that the implementation of the other key provisions of the amended order regarding the rate review will have a material impact on its financial position, results of operations or cash flows.

On May 19, 2020, the ACC Staff filed a third-party consultant's report which evaluated the effectiveness of APS's customer outreach and education program related to the 2017 Rate Case Decision. On May 29, 2020, the Chairman of the ACC filed a letter with the ACC in response to this report and is alleging that APS is out of compliance with the 2017 Rate Case Decision and is over-earning. The Chairman proposed that the current rates should be classified as interim rates and customers held harmless if APS's activities have caused the rates set in the 2017 Rate Case Decision to not be just and reasonable. Also, on May 29, 2020, a second commissioner filed a letter with the ACC agreeing with the Chairman's assertions and further asserting that the 2017 Rate Case Decision should be re-opened. On June 18, 2020, at an ACC Open Meeting, the matters raised in these letters were discussed. The ACC did not vote to move forward with any adjustments to APS's current rates. On November 4, 2020, the ACC voted to administratively close this docket.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget. In 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision.

APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2020 contained in the RES rules. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including a waiver of the residential distributed energy requirements for the 2020 implementation year. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 Demand Side Management Implementation Plan ("DSM Plan").

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2021 contained in the RES rules. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan including a waiver of the residential distributed energy requirements for the 2021 implementation year. As part of the approval, the ACC authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

On May 21, 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its integrated resource planning ("IRP"), and seek cost recovery in a rate process. The adopted rules included substantial changes since the original Recommended Opinion and Order, and thus will require supplemental rulemaking before taking effect. APS cannot predict the outcome of this matter. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS's budget proposal supports existing approved projects and commitments and requests a permanent waiver of the residential and non-residential distributed energy requirements for 2022 contained in the RES rules. The ACC has not yet ruled on the 2022 RES Implementation Plan.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Plan annually for review by and approval of the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the

achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its Lost Fixed Cost Recovery ("LFCR") mechanism (see below for discussion of the LFCR).

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan sought a requested budget of $52.6 million and requested a waiver of the Electric Energy Efficiency Standard for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels but kept the overall budget at $52.6 million.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption in the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, which was approved by the ACC on June 13, 2021.

On December 31, 2020, APS filed its 2021 DSM Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Plan that proposed an additional performance incentive for customers participating in the residential energy storage pilot approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Plan.

On April 20, 2021, APS filed a request to extend the June 1, 2021 deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved this request on

June 8, 2021.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2021 and 2020 (dollars in thousands):

	Six Months Ended June 30,	
	2021	2020
Beginning balance	$ 175,835	$ 70,137
Deferred fuel and purchased power costs — current period	135,905	26,473
Amounts (charged) refunded to customers	(10,828)	4,815
Ending balance	$ 300,912	$ 101,425

The PSA rate for the PSA year beginning February 1, 2019 was $0.001658 per kWh, as compared to the $0.004555 per kWh for the prior year. This rate was comprised of a forward component of $0.000536 per kWh and a historical component of $0.001122 per kWh. This represented a $0.002897 per kWh decrease compared to 2018. These rates went into effect as filed on February 1, 2019.

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh and consisted of a forward component of $(0.002086) per kWh and a historical component of $0.001630 per kWh. The 2020 PSA rate is a $0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh and consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase, compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021 but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA, with 50% of the rate increase effective in April 2021 and the remaining 50% of the increase effective in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh and consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase will be implemented to a rate of $0.003544 per kWh and will consist of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit, which is currently underway, to better understand the factors that contributed to the increase. APS cannot predict the outcome of this audit.

On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA. On December 29, 2020, the ACC Staff

filed its report and recommended the storage costs be included in the PSA once the systems are in-service. On January 12, 2021, the ACC approved this application but did not rule on the prudency.

Environmental Improvement Surcharge ("EIS"). The EIS permits APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 for qualified environmental improvements made during the prior calendar year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2021 application requested an increase in the charge to $10.3 million, or $1.5 million over the prior-period charge and it became effective with the first billing cycle in April 2021.

Transmission Rates, Transmission Cost Adjustor ("TCA") and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the settlement agreement entered into in 2012 regarding APS's rate case ("2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. APS reviews the proposed formula rate filing amounts with the ACC Staff. Any items or adjustments which are not agreed to by APS and the ACC Staff can remain in dispute until settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 7, 2018, APS made a filing to make modifications to its annual transmission formula to provide transmission customers the benefit of the reduced federal corporate income tax rate resulting from the Tax Cuts and Jobs Act ("Tax Act") beginning in its 2018 annual transmission formula rate update filing. These modifications were approved by FERC on May 22, 2018 and reduced APS's transmission rates compared to the rate that would have gone into effect absent these changes. On March 17, 2020, APS made a filing to make further modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Act, as well as for future local, state, and federal statutory tax rate changes.

This filing is pending with FERC.

Effective June 1, 2019, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $25.8 million for the twelve-month period beginning June 1, 2019 in accordance with the FERC-approved formula. Of this amount, wholesale customer rates increased by $21.1 million and retail customer rates would have increased by approximately $4.7 million. However, since changes in retail transmission charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved TCA balancing account, the retail revenue requirement increased by a total of $4.9 million, resulting in a decrease to residential rates and an increase to commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2019.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the twelve-month period beginning June 1, 2020 in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million. However, since changes in retail transmission charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the twelve-month period beginning June 1, 2021 in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in retail transmission charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism are currently 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 15, 2018, APS filed its 2018 annual LFCR adjustment, requesting that effective May 1, 2018, the LFCR be adjusted to $60.7 million. On February 6, 2019, the ACC approved the 2018 annual LFCR adjustment

to become effective March 1, 2019. On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). On July 10, 2019, the ACC approved APS's 2019 LFCR adjustment as filed, effective with the next billing cycle of July 2019. On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment, thus the previously approved rates continue to remain intact. The $11.8 million will continue to be maintained in the LFCR regulatory asset balancing account and will be included in APS's next LFCR application filing in accordance with the compliance requirements.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On January 8, 2018, APS filed an application with the ACC that addressed the change in the marginal federal tax rate from 35% to 21% resulting from the Tax Act and reduced rates by $119.1 million annually through an equal cents per kWh credit ("TEAM Phase I"). On February 22, 2018, the ACC approved the reduction of rates through an equal cents per kWh credit. The rate reduction was effective for the first billing cycle in March 2018.

The impact of the TEAM Phase I, over time, is expected to be earnings neutral. However, on a quarterly basis, there is a difference between the timing and amount of the income tax benefit and the reduction in revenues refunded through the TEAM Phase I related to the lower federal income tax rate. The amount of the benefit of the lower federal income tax rate is based on quarterly pre-tax results, while the reduction in revenues refunded through the TEAM Phase I is based on a per kWh sales credit which follows our seasonal kWh sales pattern and is not impacted by earnings of the Company.

On August 13, 2018, APS filed a second request with the ACC that addressed the return of an additional $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 will be recorded as a part of the balancing account and will be addressed for recovery as part of APS's 2019 ACC

rate case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit are recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million, which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which will provide an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of APS's 2019 pending rate case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit are recognized based upon APS's seasonal kWh sales pattern.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a RCP methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to September 1, 2017, based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh was included in the 2017 Settlement Agreement and became effective on September 1, 2017.

In accordance with the 2017 Rate Case Decision, APS filed its request for a third-year export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. APS's export energy price will remain at 10.5 cents per kWh until October 1, 2021.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Arizona Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. As part of the 2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

See "2016 Retail Rate Case Filing with the Arizona Corporation Commission" above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC Staff. As part of this docket, Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Burns filed suit against APS and Pinnacle West in the Superior Court of Arizona for Maricopa County in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel.

On August 4, 2017, Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Burns' amended complaint. On March 6, 2018, Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS's 2017 rate case. Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants' motions to dismiss and entered final judgment on January 18, 2019.

On February 13, 2019, Burns filed a notice of appeal. On July 12, 2019, Burns filed his opening brief in the Arizona Court of Appeals. APS filed its answering brief on October 21, 2019. The Arizona Court of Appeals originally granted the request for oral argument; however, on March 31, 2020, the court vacated the date scheduled for oral argument given the COVID-19 pandemic. The court determined that the matter could be submitted without oral argument and has taken the matter under advisement and will issue a decision without oral argument.

Burns' position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. Both APS and the ACC filed responses opposing the motion and asserting that the matter is moot. On March 4, 2021, the Court of Appeals found Burns' motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day. In its March 4, 2021 opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021 requesting that the petition be denied. The grant of review by the Arizona Supreme Court is discretionary. Pinnacle West and APS cannot predict the outcome of this matter.

Information Requests from Arizona Corporation Commissioners

On January 14, 2019, ACC Commissioner Kennedy opened a docket to investigate campaign expenditures and political participation of APS and Pinnacle West. In addition, on February 27, 2019, ACC Commissioners Burns and Dunn opened a new docket and requested documents from APS and Pinnacle West related to ACC elections and charitable contributions related to the ACC. On March 1, 2019, ACC Commissioner Kennedy issued a subpoena to APS seeking several categories of information for both Pinnacle West and APS, including political contributions, lobbying expenditures, marketing and advertising expenditures, and contributions made to 501(c)(3) and 501(c)(4) entities, for the years 2013-2018. Pinnacle West and APS voluntarily responded to both sets of requests on March 29, 2019. APS also received and responded to various follow-on requests from ACC Commissioners on these matters. Pinnacle West and APS cannot predict the outcome of these matters. The Company's CEO, Mr. Guldner, appeared at the ACC's January 14, 2020 Open Meeting regarding ACC Commissioners' questions about political spending. Mr. Guldner committed to the ACC that, during his tenure, Pinnacle West and APS, and any of their affiliated companies, will not participate in ACC campaign elections through financial contributions or in-kind contributions.

Energy Modernization Plan

On January 30, 2018, former ACC Commissioner Tobin proposed the Energy Modernization Plan, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the RES, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics.

On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and held various workshops to incorporate feedback from stakeholders and ACC Commissioners from April 2019 through July 2020. At the March 11-12, 2020 workshop, the ACC Staff committed to filing a final draft of proposed rules by July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear is defined as a clean energy resource. The proposed rules also require 50% of retail energy served be renewable by the end of 2035. A new energy efficiency standard was not included in the proposed rules. APS would be required to obtain approval of its action plan included in its IRP and seek recovery of prudently incurred costs in a rate process. If approved by the ACC Commissioners, the rules would require utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, the ACC Staff proposed changing the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020. On October 14, 2020, the ACC passed one amendment to ACC Staff's final draft energy rules that would have required electric utilities to obtain 35% of peak load (as measured in 2020) by 2030 from DSM resources, including traditional energy efficiency, demand response and other programs aimed at reducing energy usage, peak demand management and load shifting. This standard aligned with the proposed rules' three-year resource planning cycle and allowed recovery of costs through existing mechanisms until the ACC issues a decision in a future rate proceeding. On October 29, 2020, the ACC approved an amendment that would have required electric utilities to reduce their carbon emissions over 2016-2018 levels by 50% by 2032; 75% by 2040; and 100% by 2050. The ACC also approved an amendment that required utilities to install energy storage systems with an aggregate capacity equal to 5% of each utility's 2020 peak demand by 2035, of which 40% must be derived from customer-owned or customer-leased distributed storage. Another approved amendment modified the resource planning process, including requirements for the ACC to approve a utility's load forecast and resource plan, and for a utility to perform an all-source request for information to guide its resource plan. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In May 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules include a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050 and 95% reduction by December 31, 2060. Since the adopted clean energy rules differ substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures will be required before the rules become effective. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRP's from April 1, 2020 to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In March 2021, the ACC Staff requested additional time to prepare its assessment of utility IRPs. The ACC has taken no action on APS's IRP. APS cannot predict the outcome of this matter. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December

17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona, and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year power purchase agreements with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

On July 16, 2020, FERC issued a final rule revising FERC's regulations implementing PURPA. The final rule went into effect on December 31, 2020. APS is evaluating how the revised regulations may impact its operations.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur and customers will have four months to pay back their deposit and any remaining delinquent amounts. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. ACC stakeholder meetings were held in September 2019, October 2019 and January 2020 regarding the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar threshold (June 1 October 15) for disconnection moratoriums. The ACC held two public comment sessions on the draft rules and will conduct a final vote before the rules become effective. The Summer Disconnection Moratorium will remain in effect until the ACC formalizes the final rules package.

Due to the COVID-19 pandemic, APS voluntarily suspended disconnections of customers for nonpayment and waived late payment fees beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS will continue to waive late payment fees until October 15, 2021. APS has experienced and is continuing to

experience an increase in bad debt expense associated with the COVID-19 pandemic. See "COVID-19 Pandemic" above for more information.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. An ACC special open meeting workshop was held on December 3, 2018. No substantive action was taken, but interested parties were asked to submit written comments and respond to a list of questions from ACC Staff. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. Interested parties filed comments to the ACC Staff report and a stakeholder meeting and workshop to discuss the retail electric competition rules was held on July 30, 2019. ACC Commissioners submitted additional questions regarding this matter. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. The ACC held a workshop on February 25-26, 2020 on further consideration and discussion of the retail electric competition rules. During a July 15, 2020 ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC Commissioners are continuing to explore the retail electric competition rules. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019 and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. APS developed a new tool for comparing customers' rate plan options. APS had an independent third party verify that the new rate comparison tool works correctly. In February 2020, APS launched the new online rate comparison tool, which is now available for its customers. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict if any action

will be taken by the ACC at this time.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021 APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, $24 million of which is being returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. Exceptions to the Recommended Opinion and Order were filed by the parties and intervenors on December 7, 2018. The ACC has not issued a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Retail Rate Case filing with the ACC. On March 18, 2020, the ACC agreed to take administrative notice to include in the pending rate case portions of the record in this prior proceeding that are relevant to the SCRs.

On August 2, 2021, the 2019 Rate Case ROO recommended a disallowance of approximately $399 million of SCR plant investments and $61 million of SCR cost deferrals. The ACC has not issued a decision on this matter, but if the recommendation regarding the Four Corners SCR project in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS would be required to record a write-off related to the SCR cost deferrals. As of June 30, 2021, the SCR cost deferral balance is approximately $75 million net of accumulated deferred income taxes. In addition, if the recommendation regarding the SCR plant investment disallowance in the 2019 Rate Case ROO is adopted and ordered by the ACC, the amount of any loss will be determined based on the value of the SCR plant investment assets at the time the disallowance is probable and estimable and could also be affected by other regulatory and legal considerations. As of June 30, 2021, the value of the SCR plant investments is approximately $320 million, net of accumulated deferred income taxes. If a disallowance of all or a portion of the SCR plant

investments is determined to be estimable and probable, or if regulatory recovery of all or a portion of the deferred costs is determined to no longer be probable, it is reasonably possible that APS will recognize a material loss on the SCR investments and cost deferrals. For the period ended June 30, 2021, based on the fact that the 2019 Rate Case ROO is not a final decision and that APS intends to file exceptions to the 2019 Rate Case ROO related to the recommended disallowance of SCR plant investments and cost deferrals, among other factors, APS has not recorded any adjustments to write-off or write-down the SCR plant investments or cost deferrals. The pollution control assets are used and useful and are required to operate Four Corners and APS believes that these SCR investments were prudently incurred. APS cannot predict the final outcome of the decision on this matter nor reasonably estimate the amount of any potential loss.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of the Cholla Power Plant ("Cholla") and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if the United States Environmental Protection Agency ("EPA") approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020. Cholla Unit 4 was retired on December 24, 2020.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs ($48.9 million as of June 30, 2021), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. The 2017 Settlement Agreement also shortened the depreciation lives of Cholla Units 1 and 3 to 2025.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that allows for decommissioning activities to begin after the plant ceased operations.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($67 million as of June 30, 2021) plus a return on the net book value as well as other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset ($17.5 million as of June 30, 2021). APS believes it will be allowed recovery of the net book value, retirement and closure costs,

in addition to a return on its investment. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of this interest, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted. On August 2, 2021, the 2019 Rate Case ROO recommended that APS record 15% of the annual amortization of the regulatory asset as a non-operating expense. If the recommendation regarding the Navajo Plant in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS does not expect this to have a material impact on its financial statements.

7. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan, a non-qualified supplemental excess benefit retirement plan, and other postretirement benefit plans for the employees of Pinnacle West and our subsidiaries. The other postretirement benefit plans include a group life and medical plan and a post-65 retiree health reimbursement arrangement ("HRA"). Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date.

Under the HRA, included in the other postretirement benefit plan, the Pinnacle West provides a subsidy to retirees to defray the cost of a Medicare supplemental policy. In prior years, Pinnacle West has been assuming a 4.75% escalation of these benefits; however, actual escalation has been significantly less than this assumption. Accordingly, during 2020 and for future periods, the escalation assumption was reduced to 2.00%. This escalation factor assumption change, among other factors, resulted in an increase in the over-funded status of the other postretirement benefit plan as of December 31, 2020. As a result, on January 4, 2021, we initiated the transfer of approximately $106 million of assets from the other postretirement benefit plan into the Active Union Employee Medical Account. The Active Union Employee Medical Account is an existing trust account that holds assets restricted for paying active union employee medical costs (see Note 12). The transfer of other postretirement benefit plan assets into the Active Union Employee Medical Account permits access to approximately $106 million of assets for the sole purpose of paying active union employee medical benefits. This transfer of assets into the Active Union Employee Medical Account is consistent with the terms of a similar 2018 transaction.

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants) (dollars in thousands):

	Pension Benefits				Other Benefits			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020	2021	2020	2021	2020
Service cost — benefits earned during the period	$ 14,939	$ 13,859	$ 30,618	$ 28,116	$ 4,341	$ 5,401	$ 8,898	$ 11,118
Non-service costs (credits):								
Interest cost on benefit obligation	24,614	29,522	49,283	59,283	4,095	6,417	8,257	12,929
Expected return on plan assets	(50,706)	(46,915)	(101,314)	(93,721)	(10,361)	(10,019)	(20,722)	(20,038)
Amortization of:								
Prior service credit	—	—	—	—	(9,427)	(9,394)	(18,854)	(18,788)
Net actuarial loss (gain)	3,989	8,295	7,974	17,306	(2,641)	—	(5,046)	—
Net periodic benefit cost/(benefit)	$ (7,164)	$ 4,761	$(13,439)	$ 10,984	$(13,993)	$ (7,595)	$(27,467)	$(14,779)
Portion of cost/(benefit) charged to expense	$ (8,614)	$ 271	$(16,625)	$ 1,613	$ (9,608)	$ (5,056)	$(19,136)	$(10,512)

Contributions

Pinnacle West has not made voluntary contributions to our pension plan year-to-date in 2021. The minimum required contributions for the pension plan are zero for the next three years. Pinnacle West expects to make voluntary contributions up to $100 million in 2021 and zero in 2022 and 2023. Pinnacle West does not expect to make any contributions over this period to our other postretirement benefit plans.

8. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. Prior to April 1, 2021, the lease terms allowed APS the right to retain the assets through 2023 under one lease and 2033 under the other two leases. On April 1, 2021, APS executed an amended lease agreement with one of the VIE lessor trust entities relating to the lease agreement with the term ending in 2023. The amendment extends the lease term for this lease through 2033 and changes the lease payment. As a result of this amendment, APS will now retain the assets through 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2021 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

For regulatory reporting purposes, APS accounts for the three leases as operating leases for income statement and cash flow statement purposes, and for balance sheet purposes all three leases are classified as finance leases. See Note 15 for a discussion of leases.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the Nuclear Regulatory Commission ("NRC") issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $307 million beginning in 2021, and up to $501 million over the lease terms.

9. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, emissions allowances, and in interest rates. Risks associated with market volatility are managed by utilizing various physical and financial derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and natural gas. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are presented gross, which increases both revenues and fuel and purchased power costs in our Comparative Statements of Income, but does not impact our financial condition, net income or cash flows.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheets as an asset or liability and are measured at fair value. See Note 11 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 6). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

The following table shows the outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	**Unit of Measure**	**June 30, 2021**	**December 31, 2020**
Power	GWh	368	368
Gas	Billion cubic feet	189	205

Gains and Losses from Derivative Instruments

The following table provides information about APS's gains and losses from derivative instruments in designated cash flow accounting hedging relationships (dollars in thousands):

	Financial Statement Location	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
Commodity Contracts		**2021**	**2020**	**2021**	**2020**
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	$ —	$ (349)	$ —	$ (763)

(a) During the three and six months ended June 30, 2021 and 2020, we had no gains or losses reclassified from accumulated Other Comprehensive Income ("OCI") to earnings related to discontinued cash flow hedges.

(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that no amounts will be reclassified from accumulated OCI into income, as the delivery period for all derivative instruments in designated cash flow accounting hedging relationships have lapsed.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments (dollars in thousands):

	Financial Statement Location	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
Commodity Contracts		**2021**	**2020**	**2021**	**2020**
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ 95,116	$ (4,894)	$121,975	$(34,971)

(a) Amounts are before the effect of PSA deferrals.

Derivative Instruments in the Comparative Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements and are reported gross on the Comparative Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The following tables provide information about the fair value of our risk management activities reported on a gross basis, and the impacts of offsetting relating to transactions executed under master netting arrangements. While certain amounts may be eligible for offsetting under master netting arrangements, for FERC reporting purposes we do not offset on the balance sheet. These amounts relate to commodity contracts and are located in the assets and liabilities from derivative instrument lines of our Comparative Balance Sheets.

As of June 30, 2021:	**Gross Recognized**	**Eligible for Offsetting**		**Net Derivatives After Impacts of**
(dollars in thousands)	**Derivatives (a)**	**Derivatives**	**Cash Collateral/ Other (b)**	**Offsetting**
Current Assets	$ 83,677	$ (1,368)	$ —	$ 82,309
Investments and Other Assets	27,305	—	—	27,305
Total Assets	110,982	(1,368)	—	109,614
Current Liabilities	(1,595)	1,368	—	(227)
Deferred Credits and Other	—	—	—	—
Total Liabilities	(1,595)	1,368	—	(227)
Total	$ 109,387	$ —	$ —	$ (109,387)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.

(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting. We had total cash collateral received from counterparties of $1,285.

As of December 31, 2020:	**Gross Recognized**	**Eligible for Offsetting**		**Net Derivatives After Impacts of**
(dollars in thousands)	**Derivatives (a)**	**Derivatives**	**Cash Collateral/ Other (b)**	**Offsetting**
Current Assets	$ 5,870	$ (2,939)	$ —	$ 2,931
Investments and Other Assets	3,150	(1,332)	—	1,818
Total Assets	9,020	(4,271)	—	4,749
Current Liabilities	(9,211)	2,939	—	(6,272)
Deferred Credits and Other	(12,394)	1,332	—	(11,062)
Total Liabilities	(21,605)	4,271	—	(17,334)
Total	$ (12,585)	$ —	$ —	$ (12,585)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.

(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting. We had total cash collateral received from counterparties of $1,285.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of June 30, 2021, we have two counterparties for which our exposure represents approximately 35% of $110 million of risk management assets. This exposure relates to master agreements with counterparties and both are rated as investment grade. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

The following table provides information about our derivative instruments that have credit-risk-related contingent features (dollars in thousands):

	June 30, 2021
Aggregate fair value of derivative instruments in a net liability position	$ 1,595
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered	—

We also have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $87 million if our debt credit ratings were to fall below investment grade.

10. Commitments and Contingencies

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2022.

APS has submitted six claims pursuant to the terms of the August 18, 2014 settlement agreement, for six separate time periods during July 1, 2011 through June 30, 2019. The DOE has approved and paid $99.7 million for these claims (APS's share is $29.0 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers (see Note 6). On November 2, 2020, APS filed its seventh claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). On March 15, 2021, the DOE approved a payment of $12.1 million (APS's share is $3.5 million) and on April 16, 2021, APS received this payment.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident of up to approximately $13.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of approximately $13.1 billion of liability coverage is provided through a mandatory industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $137.6 million, subject to a maximum annual premium of approximately $20.5 million per incident. Based on APS's ownership interest in the

three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $120.1 million, with a maximum annual retrospective premium of approximately $17.9 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $22.4 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $63.3 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

Contractual Obligations

As of June 30, 2021, our fuel and purchased power commitments have increased from the information provided in our 2020 FERC Form 1. The increase is primarily due to new purchased power and energy storage commitments of approximately $624 million. The majority of the changes relate to 2026 and thereafter.

Other than the item described above, there have been no material changes, as of June 30, 2021, outside the normal course of business in contractual obligations from the information provided in our 2020 FERC Form 1. See Note 5 for discussion regarding changes in our short-term and long-term debt obligations. See Note 8 for discussion regarding changes to our contractual obligations related to the Palo Verde sale leaseback transactions.

Superfund-Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible ("PRPs"). PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS during the fourth quarter of 2021. We estimate that our costs related to this investigation and study will be approximately $3 million. We anticipate incurring additional expenditures in the future, but because

the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation, but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Arizona Attorney General Matter

APS received civil investigative demands from the Attorney General seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021 APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, $24 million of which is being returned to customers as restitution.

Four Corners SCR Cost Recovery

As part of APS's rate case filing in 2019, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On August 2, 2021, the 2019 Rate Case ROO recommended a disallowance of approximately $399 million of SCR plant investments and $61 million of SCR cost deferrals. The ACC has not issued a decision on this matter, but if the recommendation regarding the Four Corners SCR project in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS would be required to record a write-off related to the SCR cost deferrals. As of June 30, 2021, the SCR cost deferral balance is approximately $75 million net of accumulated deferred income taxes. In addition, if the recommendation regarding the SCR plant investment disallowance in the 2019 Rate Case ROO is adopted and ordered by the ACC, the amount of any loss will be determined based on the value of the SCR plant investment assets at the time the disallowance is probable and estimable and could also be affected by other regulatory and legal considerations. As of June 30, 2021, the value of the SCR plant investments is approximately $320 million, net of accumulated deferred income taxes. If a disallowance of all or a portion of the SCR plant investments is determined to be estimable and probable, or if regulatory recovery of all or a portion of the deferred costs is determined to no longer be probable, it is reasonably possible that APS will recognize a material loss on the SCR investments and cost deferrals. For the period ended June 30, 2021, based on the fact that the 2019 Rate Case ROO is not a final decision and that APS intends to file exceptions to the 2019 Rate Case ROO related to the recommended disallowance of SCR plant investments and cost deferrals, among other factors, APS has not recorded any adjustments to write-off or write-down the SCR plant investments or cost deferrals. The pollution control assets are used and useful and are required to operate Four Corners and APS believes that these SCR investments were prudently incurred. APS cannot predict the final outcome of the decision on this matter nor reasonably estimate the amount of any potential loss.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on Four Corners. EPA required the plant to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plant. In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See below for details of the Cholla BART approval.

Four Corners. Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. In addition, APS and El Paso Electric Company ("El Paso") entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4C Acquisition, LLC ("4CA") purchased the El Paso interest on July 6, 2016. Navajo Transitional Energy Company, LLC ("NTEC") purchased the interest from 4CA on July 3, 2018. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest.

Cholla. In early 2017, EPA approved a final rule containing a revision to Arizona's State Implementation Plan ("SIP") for Cholla that implemented BART requirements for this facility, which did not require the installation of any new pollution control capital improvements. In conjunction with the closure of Cholla Unit 2 in 2015, APS has committed to ceasing coal combustion within Units 1 and 3 by April 2025. PacifiCorp retired Cholla Unit 4 at the end of 2020. (See "Cholla" in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset).

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On July 29, 2020, EPA took final action on new regulations establishing revised deadlines for initiating the closure of unlined CCR surface impoundments, April 11, 2021 at the latest. All APS disposal units subject to these closure requirements were closed as of April 11, 2021.

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's July 29, 2020 final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure (which would allow the continued disposal of CCR within the facility's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025) was submitted to EPA on November 30, 2020 and is currently pending. This application will be subject to public comment and, potentially, judicial review.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $27 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased

operating and initiated closure by April 11, 2021 at the latest (except for those disposal units subject to alternative closure). APS initiated an assessment of corrective measures on January 14, 2019 and expects such assessment will continue through late-2021. As part of this assessment, APS continues to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS will solicit input from the public, host public hearings, and select remedies as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan/Affordable Clean Energy Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. While the Biden administration has expressed an intent to regulate carbon emissions in this sector more aggressively under the Clean Air Act, we cannot at this time predict the outcome of pending EPA rulemaking proceedings in response to the court's recent ACE decision.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019 filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020 and the EAB denied the environmental group petition on September 30, 2020. On January 22, 2021, the environmental groups filed a

petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. The September 2019 permit remains in effect pending this appeal. The parties are presently engaged in mediation to settle this dispute. We cannot predict the outcome of this appeal proceeding, the ongoing mediation, and, if such appeal is successful, whether that outcome will have a material impact on our financial position, results of operations, or cash flows.

Four Corners 4CA Matter

On July 6, 2016, 4CA purchased El Paso's 7% interest in Four Corners. NTEC purchased this 7% interest on July 3, 2018 from 4CA. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and is paying 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. The note is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement. As of June 30, 2021, the note has a remaining balance of $18 million. NTEC continues to make payments in accordance with the terms of the note. Due to its short-remaining term, among other factors, there are no expected credit losses associated with the note.

In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. The amount under this formula for calendar year 2018 (up to the date that NTEC purchased the 7% interest) was approximately $10 million, which was due to 4CA on December 31, 2019. Such payment was satisfied in January 2020 by NTEC directing to 4CA a prepayment from APS of future coal payment obligations of which the prepayment has been fully utilized as of June 2020.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of June 30, 2021, standby letters of credit totaled $0.2 million and would have expired in 2021, subsequently in April of 2021 an extension was effective that reset the expiration dates to 2022. As of June 30, 2021, surety bonds expiring through 2022 totaled $16 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

11. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 Other significant observable inputs, including quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active, and model-derived valuations whose inputs are observable (such as yield curves).

Level 3 Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category may include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of Net Asset Value ("NAV") as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV as a practical expedient are included in our fair value disclosures; however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 9 in the 2020 Form 1 for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3.

Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account and the active union employee medical account. See Note 12 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustees' and escrow agent's internal operating controls and valuation processes.

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These fixed income instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short-term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trusts's equity security investments are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of

the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

The nuclear decommissioning trusts and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid, investments are valued using active market prices.

Fair Value Tables

The following table presents the fair value at June 30, 2021 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 84,594	$ 26,388	$ —		$ 110,982
Nuclear Decommissioning Trust:						
Equity securities	22,749	—	—	(9,506)	(a)	13,243
U.S. commingled equity funds	—	—	—	702,836	(b)	702,836
U.S. Treasury debt	167,584	—	—	—		167,584
Corporate debt	—	150,681	—	—		150,681
Mortgage-backed debt securities	—	119,481	—	—		119,481
Municipal bonds	—	59,876	—	—		59,876
Other fixed income	—	9,387	—	—		9,387
Subtotal nuclear decommissioning	190,333	339,425	—	693,330		1,223,088
Other special use funds:						
Equity securities	19,904	—	—	952	(a)	20,856
U.S Treasury debt	324,418	—	—	—		324,418
Municipal bonds	—	13,162	—	—		13,162
Subtotal other special use funds	344,322	13,162	—	952		358,436
Total Assets	$ 534,655	$ 437,181	$ 26,388	$ 694,282		$ 1,692,506
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (1,586)	$ (9)	$ —		$ (1,595)

(a) Represents net pending securities sales and purchases.

(b) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

The following table presents the fair value at December 31, 2020 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 9,016	$ 4	$ —		$ 9,020
Nuclear decommissioning trust:						
Equity securities	29,796	—	—	(17,828)	(a)	11,968
U.S. commingled equity funds	—	—	—	610,055	(b)	610,055
U.S. Treasury debt	164,514	—	—	—		164,514
Corporate debt	—	149,509	—	—		149,509
Mortgage-backed securities	—	99,623	—	—		99,623
Municipal bonds	—	89,705	—	—		89,705
Other fixed income	—	13,061	—	—		13,061
Subtotal nuclear decommissioning	194,310	351,898	—	592,227		1,138,435
Other special use funds:						
Equity securities	37,337	—	—	504	(a)	37,841
U.S Treasury debt	203,220	—	—	—		203,220
Municipal bonds	—	13,448	—	—		13,448
Subtotal other special use funds	240,557	13,448	—	504		254,509
Total Assets	$ 434,867	$ 374,362	$ 4	$ 592,731		$ 1,401,964
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (20,498)	$ (1,107)	$ —		$ (21,605)

(a) Represents net pending securities sales and purchases.

(b) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote or other characteristics of the product. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 6).

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

Financial Instruments Not Carried at Fair Value

The carrying value of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 5 for our long-term debt fair values.

12. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds

We have investments in debt and equity securities held in Nuclear Decommissioning Trusts, Coal Reclamation Escrow Account, and an Active Union Employee Medical Account. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments at their fair value on our Comparative Balance Sheets. See Note 11 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts — APS established external decommissioning trusts in accordance with NRC regulations to fund the future costs APS expects to incur to decommission Palo Verde. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities.

Coal Reclamation Escrow Account — APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because of the ability of APS to recover coal mine reclamation costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

Active Union Employee Medical Account — APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2020 and 2019, APS was reimbursed $14 million and $15 million, respectively, for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to active union

employee medical account investments are included within the other special use funds in the table below. On January 4, 2021, an additional $106 million of investments were transferred from APS other postretirement benefit trust assets into the active union employee medical account (see Note 7).

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	June 30, 2021					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 725,585	$ 19,904	$ 745,489		$ 510,432	$ —
Available for sale-fixed income securities	507,009	337,580	844,589	(a)	31,269	(1,357)
Other	(9,506)	952	(8,554)	(b)	—	—
Total	$ 1,223,088	$ 358,436	$1,581,524		$ 541,701	$ (1,357)

(a) As of June 30, 2021, the amortized cost basis of these available-for-sale investments is $815 million.

(b) Represents net pending securities sales and purchases.

	December 31, 2020					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 639,851	$ 37,337	$ 677,188		$ 421,666	$ —
Available for sale-fixed income securities	516,412	216,668	733,080	(a)	46,581	(398)
Other	(17,828)	504	(17,324)	(b)	—	—
Total	$ 1,138,435	$ 254,509	$1,392,944		$ 468,247	$ (398)

(a) As of December 31, 2020, the amortized cost basis of these available-for-sale investments is $687 million.

(b) Represents net pending securities sales and purchases.

The following table sets forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities (dollars in thousands):

	Three Months Ended June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2021			
Realized gains	$ 1,406	$ —	$ 1,406
Realized losses	(1,146)	—	(1,146)
Proceeds from the sale of securities (a)	190,340	17,524	207,864
2020			
Realized gains	$ 4,500	$ —	$ 4,500
Realized losses	(1,621)	—	(1,621)
Proceeds from the sale of securities (a)	176,942	19,830	196,772

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

	Six Months Ended June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2021			
Realized gains	$ 4,374	$ —	$ 4,374
Realized losses	(5,294)	—	(5,294)
Proceeds from the sale of securities (a)	425,068	162,774	587,842
2020			
Realized gains	$ 7,813	$ —	$ 7,813
Realized losses	(3,848)	—	(3,848)
Proceeds from the sale of securities (a)	355,138	36,721	391,859

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

Fixed Income Securities Contractual Maturities

The fair value of APS's fixed income securities, summarized by contractual maturities, at June 30, 2021, is as follows (dollars in thousands):

	Nuclear Decommissioning Trust	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 28,151	$ 26,123	$ 40,263	$ 94,537
1 year – 5 years	133,054	35,880	162,728	331,662
5 years – 10 years	131,462	2,676	61,288	195,426
Greater than 10 years	214,342	8,622	—	222,964
Total	$ 507,009	$ 73,301	$ 264,279	$ 844,589

13. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in APS's accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

Three Months Ended June 30	Pension and Other Postretirement Benefits	Derivative Instruments	Total
Balance March 31, 2021	$ (39,991)	$ —	$ (39,991)
OCI (loss) before reclassifications	(914)	—	(914)
Amounts reclassified from accumulated other comprehensive loss	1,073 (a)	—	1,073
Balance June 30, 2021	$ (39,832)	$ —	$ (39,832)
Balance March 31, 2020	$ (33,935)	$ (262)	$ (34,197)
OCI (loss) before reclassifications	(1,951)	—	(1,951)
Amounts reclassified from accumulated other comprehensive loss	861 (a)	262 (b)	1,123
Balance June 30, 2020	$ (35,025)	$ —	$ (35,025)

Sic Months Ended June 30	Pension and Other Postretirement Benefits	Derivative Instruments	Total
Balance December 31, 2020	$ (40,918)	$ —	$ (40,918)
OCI (loss) before reclassifications	(914)	—	(914)
Amounts reclassified from accumulated other comprehensive loss	2,000 (a)	— (b)	2,000
Balance June 30, 2021	$ (39,832)	$ —	$ (39,832)
Balance December 31, 2019	$ (34,948)	$ (574)	$ (35,522)
OCI (loss) before reclassifications	(1,951)	292	(1,659)
Amounts reclassified from accumulated other comprehensive loss	1,874 (a)	282 (b)	2,156
Balance June 30, 2020	$ (35,025)	$ —	$ (35,025)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.

(b) These amounts primarily represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 9.

14. Income Taxes

The Tax Act reduced the corporate tax rate to 21% effective January 1, 2018. As a result of this rate reduction, the Company recognized a $1.14 billion reduction in its net deferred income tax liabilities as of December 31, 2017. In accordance with accounting for regulated companies, the effect of this rate reduction was substantially offset by a net regulatory liability.

Federal income tax laws require the amortization of a majority of the balance over the remaining regulatory life of the related property. As a result of the modifications made to the annual transmission formula rate during the second quarter of 2018, the Company began amortization of FERC jurisdictional net excess deferred tax liabilities in 2018. On March 13, 2019, the ACC approved the Company's proposal to amortize non-depreciation related net excess deferred tax liabilities subject to its jurisdiction over a twelve- month period. As a result, the Company began amortization in March 2019. The Company recorded $14 million of income tax benefit related to the amortization of these non-depreciation related net excess deferred tax liabilities as of March 31, 2020, with these non-depreciation related net excess deferred tax liabilities being fully amortized as of March 31, 2020. On October 29, 2019, the ACC approved the Company's proposal to amortize depreciation related net excess deferred tax liabilities subject to its jurisdiction over a 28.5-year period with amortization to retroactively begin as of January 1, 2018. The Company recorded $14 million of income tax benefit related to amortization of these depreciation related net excess deferred tax liabilities for the periods ending June 30, 2021 and June 30, 2020. See Note 6 for more details.

15. Leases

We lease certain land, buildings, vehicles, equipment and other property through rental agreements with varying terms, provisions, and expiration dates. APS also has certain purchased power agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2021 through 2050.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities (see Note 8). On April 1, 2021 one of the three leases was amended to extend the lease term and modify the lease payment. The other two leases were not impacted by this amendment. For regulatory reporting purposes, APS accounts for the three Palo Verde Unit 2 leases as operating leases for income statement and cash flow statement purposes, and for balance sheet purposes they are classified as finance leases.

On May 1, 2021 APS had a new purchased power lease contract that commenced. The lease term ends on October 31, 2027. This lease allows APS the right to the generation capacity from a natural-gas fueled generator during the months of May through October over the contract term. APS does not operate or maintain the leased asset. APS controls the dispatch of the leased asset during the months of May through October and is required to pay a fixed monthly capacity payment during these periods of use. For these types of leased assets APS has elected to combine both the lease and non-lease payment components and accounts for the entire fixed payment as a lease obligation. This purchased power lease contract is accounted for as an operating lease. The contract does not contain a purchase option or term extension option. In addition to the fixed monthly capacity payment, APS must also pay variable charges based on the actual production volume of the asset. The variable consideration is not included in the measurement of our lease obligation.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

NOTES TO FINANCIAL STATEMENTS (Continued)

The following tables provide information related to our lease costs (dollars in thousands):

	Three Months Ended June 30, 2021			
	Palo Verde Unit 2 Leases	Purchased Power Lease Contracts	Other Land, Property & Equipment Leases	Totals
Operating lease cost	$ —	$ 29,514	$ 4,551	$ 34,065
Finance lease cost	5,314 (a)	—	—	5,314
Variable lease cost	—	40,539	240	40,779
Short term lease cost	—	—	1,235	1,235
Total lease cost	$ 5,314	$ 70,053	$ 6,026	$ 81,393

	Three Months Ended June 30, 2020			
	Palo Verde Unit 2 Leases	Purchased Power Lease Contracts	Other Land, Property & Equipment Leases	Totals
Operating lease cost	$ 1,712	$ 17,221	$ 4,573	$ 23,506
Finance lease cost	3,974 (a)	—	—	3,974
Variable lease cost	—	40,821	238	41,059
Short term lease cost	—	—	996	996
Total lease cost	$ 5,686	$ 58,042	$ 5,807	$ 69,535

	Six Months Ended June 30, 2021			
	Palo Verde Unit 2 Leases	Purchased Power Lease Contracts	Other Land, Property & Equipment Leases	Totals
Operating lease cost	$ —	$ 29,514	$ 9,145	$ 38,659
Finance lease cost	10,628 (a)	—	—	10,628
Variable lease cost	—	62,027	478	62,505
Short term lease cost	—	—	2,196	2,196
Total lease cost	$ 10,628	$ 91,541	$ 11,819	$ 113,988

	Six Months Ended June 30, 2020			
	Palo Verde Unit 2 Leases	Purchased Power Lease Contracts	Other Land, Property & Equipment Leases	Totals
Operating lease cost	$ 3,424	$ 17,221	$ 9,148	$ 29,793
Finance lease cost	7,948 (a)	—	—	7,948
Variable lease cost	—	61,394	464	61,858
Short term lease cost	—	—	1,786	1,786
Total lease cost	$ 11,372	$ 78,615	$ 11,398	$ 101,385

(a) For regulatory purposes the costs relating to these finance leases are reported as a component of operating expense.

Lease costs are primarily included as a component of operating expenses on our Comparative Statements of Income. Lease costs relating to purchased power lease contracts are recorded in fuel and purchased power on the Comparative Statements of Income, and are subject to recovery under the PSA or RES (see Note 6). The tables above reflect the lease cost amounts before the effect of regulatory deferral under the PSA and RES. Variable lease costs are recognized in the period the costs are incurred, and primarily relate to renewable purchased power lease contracts. Payments under most renewable purchased power lease contracts are dependent upon environmental factors, and due to the inherent uncertainty associated with the reliability of the fuel source, the payments are considered variable and are excluded from the measurement of lease liabilities and right-of-use lease assets. Certain of our lease agreements have lease terms with non-consecutive periods of use. For these agreements we recognize lease costs during the periods of use. Leases with initial terms of 12 months or less are considered short-term leases and are not recorded on the balance sheet.

The following table provides information related to the maturity of our lease liabilities (dollars in thousands):

	June 30, 2021				
	Finance Leases	Operating Leases			
Year	Palo Verde Unit 2 Finance Leases	Purchased Power Lease Contracts	Other Land, Property & Equipment Leases	Total Operating Leases	Total
2021 (remaining six months of 2021)	$ 10,628	$ 95,596	$ 7,681	$ 103,277	$ 113,905
2022	21,255	103,744	11,689	115,433	136,688
2023	21,255	106,161	9,357	115,518	136,773
2024	21,255	108,634	6,763	115,397	136,652
2025	21,255	111,166	4,984	116,150	137,405
2026	21,255	75,099	3,787	78,886	100,141
Thereafter	148,786	39,106	33,261	72,367	221,153
Total lease commitments	265,689	639,506	77,522	717,028	982,717
Less imputed interest	59,558	25,803	17,114	42,917	102,475
Total lease liabilities	$ 206,131	$ 613,703	$ 60,408	$ 674,111	$ 880,242

We recognize lease assets and liabilities upon lease commencement. At June 30, 2021, we have lease arrangements, that have been executed but have not yet commenced. These arrangements relate to energy storage agreements, with lease commencement dates expected to begin in June 2022 with terms ending through December 2042. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $392 million over the term of the arrangements.

The following tables provide other additional information related to lease liabilities (dollars in thousands):

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Cash paid for amounts included in the measurement of operating lease liabilities - operating cash flows:	$ 12,979	$ 10,898
Cash paid for amounts included in the measurement of finance lease liabilities - operating cash flows:	$ 10,628	$ 7,948
Right-of-use operating lease assets obtained in exchange for operating lease liabilities:	$ 248,694	$ 434,997
Right-of-use operating lease assets obtained in exchange for finance lease liabilities:	$ 58,470	$ —

	June 30, 2021		December 31, 2020	
	Finance Leases	Operating Leases	Finance Leases	Operating Leases
Weighted average remaining lease term	13 years	6 years	13 years	6 years
Weighted average discount rate (a)	4.14 %	1.71%	4.59 %	1.76%

(a) Most of our lease agreements do not contain an implicit rate that is readily determinable. For these agreements we use our incremental borrowing rate to measure the present value of lease liabilities. We determine our incremental borrowing rate at lease commencement based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We use the implicit rate when it is readily determinable.

16. Asset Retirement Obligations

During the six months ended June 30, 2021, the Company revised its cost estimates for existing Asset Retirement Obligations (ARO) at Cholla related to updated estimates for the closure of ponds and facilities, which resulted in an increase to the ARO of $11.1 million. (See additional details in Notes 6 and 10.)

The following schedule shows the change in our asset retirement obligations for the six months ended June 30, 2021 (dollars in thousands):

	2021
Asset retirement obligations at January 1, 2021	$ 705,083
Changes attributable to:	
Accretion expense	18,828
Settlements	(2,853)
Estimated cash flow revisions	10,932
Asset retirement obligations at June 30, 2021	$ 731,990

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 6.

17. New Accounting Standards

ASU 2021-05, Leases: Certain Leases with Variable Lease Payments

In July 2021, a new accounting standard was issued that amends the lease accounting guidance. The amended guidance will require lessors to account for certain lease transactions, that contain variable lease payments, as operating leases. The amendments are intended to eliminate the recognition of any day-one loss associated with certain sales-type and direct-financing lease transactions. The changes do not impact lessee accounting. The new guidance is effective for us on January 1, 2022 and may be adopted using either a retrospective or prospective approach. As we typically are not the lessor in these type of lease transactions, we do not expect the adoption of this guidance will have a material impact on our financial statements.

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Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net of tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year to date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available for Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(34,947,757)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,873,883
3	Preceding Quarter/Year to Date Changes in Fair Value				(1,950,803)
4	Total (lines 2 and 3)				(76,920)
5	Balance of Account 219 at End of Preceding Quarter/Year				(35,024,677)
6	Balance of Account 219 at Beginning of Current Year				(40,918,418)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,999,970
8	Current Quarter/Year to Date Changes in Fair Value				(913,761)
9	Total (lines 7 and 8)				1,086,209
10	Balance of Account 219 at End of Current Quarter/Year				(39,832,209)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1		(574,108)	(35,521,865)		
2		282,419	2,156,302		
3		291,756	(1,659,047)		
4		574,175	497,255	232,462,893	232,960,148
5		67	(35,024,610)		
6		68	(40,918,350)		
7			1,999,970		
8			(913,761)		
9			1,086,209	255,033,888	256,120,097
10		68	(39,832,141)		

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Document Accession #: 20210826-8033 Filed Date: 08/26/2021

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	20,618,523,948	20,618,523,948
4	Property Under Capital Leases	923,541,877	923,541,877
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,362,863,602	1,362,863,602
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	22,904,929,427	22,904,929,427
9	Leased to Others		
10	Held for Future Use	10,206,915	10,206,915
11	Construction Work in Progress	945,265,580	945,265,580
12	Acquisition Adjustments	255,525,921	255,525,921
13	Total Utility Plant (8 thru 12)	24,115,927,843	24,115,927,843
14	Accum Prov for Depr, Amort, & Depl	8,113,483,585	8,113,483,585
15	Net Utility Plant (13 less 14)	16,002,444,258	16,002,444,258
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	7,072,538,016	7,072,538,016
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	969,815,126	969,815,126
22	Total In Service (18 thru 21)	8,042,353,142	8,042,353,142
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	71,130,443	71,130,443
33	Total Accum Prov (equals 14) (22,26,30,31,32)	8,113,483,585	8,113,483,585

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
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ELECTRIC PLANT IN SERVICE AND ACCUMULATED PROVISION FOR DEPRECIATION BY FUNCTION

1. Report below the original cost of plant in service by function. In addition to Account 101, include Account 102, and Account 106. Report in column (b) the original cost of plant in service and in column(c) the accumulated provision for depreciation and amortization by function.

Line No.	Item (a)	Plant in Service Balance at End of Quarter (b)	Accumulated Depreciation and Amortization Balance at End of Quarter (c)
1	Intangible Plant	1,017,658,139	732,472,530
2	Steam Production Plant	2,289,659,296	1,079,416,158
3	Nuclear Production Plant	3,246,169,266	1,745,529,460
4	Hydraulic Production Conventional		
5	Hydraulic Production Pumped Storage		
6	Other Production	3,513,958,820	1,064,286,278
7	Transmission	3,345,290,507	984,312,086
8	Distribution	7,299,339,035	1,935,117,418
9	Regional Transmission and Market Operation		
10	General	1,269,312,487	501,219,212
11	TOTAL (Total of lines 1 through 10)	21,981,387,550	8,042,353,142

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Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	FACIL STDY,WA402793	435	143		143
23	FACIL STDY,WA402826	1,060	143		143
24	FACIL STDY,WA425876	(1,708)	143		143
25	FACIL STDY,WA431805	(534)	143		143
26	FACIL STDY,WA431809	(399)	143		143
27	FACIL STDY,WA431939	(886)	143		143
28	FACIL STDY,WA432055	(2,019)	143		143
29	FACIL STDY,WA432060	15,378	143		143
30	FACIL STDY,WA444215	(4,421)	143		143
31	FACIL STDY,WA444217	(4,416)	143		143
32	FACIL STDY,WA459370	(2,377)	143		143
33	FACIL STDY,WA459429	(2,105)	143		143
34	FACIL STDY,WA459497	(2,440)	143		143
35	FACIL STDY,WA459537	(426)	143	(52,700)	143
36	FACIL STDY,WA459895	(1,069)	143		143
37	FACIL STDY,WA459896	(4,353)	143		143
38	FACIL STDY,WA488493	(1,872)	143		143
39	FACIL STDY,WA517285	(1,704)	143		143
40	FACIL STDY,WA565967	(79)	143		143

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	FACIL STDY,WA602005	497	143		143
23	FACIL STDY,WA603218	17	143		143
24	FACIL STDY,WA603220	17	143		143
25	SMG FACSTD,WA565767	4,112	143		143
26	SMG FACSTD,WA603213	98	143		143
27	SMG FACSTD,WA603214	98	143		143
28	SMG FACSTD,WA603216	98	143		143
29	SMG FACSTD,WA603217	98	143		143
30	SMG FACSTD,WA603223	747	143		143
31	SMG FACSTD,WA603224	98	143		143
32	SMG SISSTD,WA488622	7,353	143		143
33	SMG SISSTD,WA488624	10,252	143		143
34	SMG SISSTD,WA488625	1,088	143		143
35	SMG SISSTD,WA488628	(724)	143		143
36	SMG SISSTD,WA488629	(9,888)	143		143
37	SMG SISSTD,WA540197	(227)	143	(5,107)	143
38	SMG SISSTD,WA545623	529	143		143
39	SMG SISSTD,WA545625	1,262	143		143
40	SMG SISSTD,WA545626	1,393	143		143

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	SMG SISSTD,WA546912	(113)	143		143
23	SMG SISSTD,WA573994	809	143		143
24	SMG SISSTD,WA606497	117	143	(30,000)	143
25	SMG SISSTD,WA606843	237	143	(30,000)	143
26	SYSIMPTSTD,WA383670	(7,301)	143		143
27	SYSIMPTSTD,WA384886	(1,153)	143		143
28	SYSIMPTSTD,WA402547	(3,962)	143		143
29	SYSIMPTSTD,WA425874	(1,214)	143		143
30	SYSIMPTSTD,WA431719	(1,235)	143		143
31	SYSIMPTSTD,WA431807	(218)	143		143
32	SYSIMPTSTD,WA431944	(2,142)	143		143
33	SYSIMPTSTD,WA431968	50,027	143		143
34	SYSIMPTSTD,WA432059	20,090	143		143
35	SYSIMPTSTD,WA450463	(173)	143		143
36	SYSIMPTSTD,WA459432	(4,375)	143		143
37	SYSIMPTSTD,WA459505	(291)	143		143
38	SYSIMPTSTD,WA488489	(2,645)	143		143
39	SYSIMPTSTD,WA488579	(539)	143		143
40	SYSIMPTSTD,WA488582	643	143		143

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	SYSIMPTSTD,WA503830	21,887	143		143
23	SYSIMPTSTD,WA511477	(18)	143		143
24	SYSIMPTSTD,WA511627	724	143		143
25	SYSIMPTSTD,WA516333	(2,138)	143		143
26	SYSIMPTSTD,WA516518	(2,164)	143		143
27	SYSIMPTSTD,WA516741	(2,187)	143		143
28	SYSIMPTSTD,WA517253	19,450	143		143
29	SYSIMPTSTD,WA517446	(1,625)	143		143
30	SYSIMPTSTD,WA517447	(1,928)	143		143
31	SYSIMPTSTD,WA517448	(1,515)	143		143
32	SYSIMPTSTD,WA517449	(1,571)	143		143
33	SYSIMPTSTD,WA532273	(4)	143		143
34	SYSIMPTSTD,WA532276	(9)	143		143
35	SYSIMPTSTD,WA534568	(1,309)	143		143
36	SYSIMPTSTD,WA539190	(2,108)	143		143
37	SYSIMPTSTD,WA544770	12,067	143		143
38	SYSIMPTSTD,WA545423	12,070	143		143
39	SYSIMPTSTD,WA545425	185	143		143
40	SYSIMPTSTD,WA545531	1,089	143		143

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	SYSIMPTSTD,WA545722	(1,686)	143		143
23	SYSIMPTSTD,WA545728	22,153	143		143
24	SYSIMPTSTD,WA545757	(3,866)	143		143
25	SYSIMPTSTD,WA546276	(2,093)	143		143
26	SYSIMPTSTD,WA546547	(3,524)	143	250,000	143
27	SYSIMPTSTD,WA546548	11,674	143		143
28	SYSIMPTSTD,WA546664	24,076	143		143
29	SYSIMPTSTD,WA546667	(2,099)	143		143
30	SYSIMPTSTD,WA546767	12,195	143		143
31	SYSIMPTSTD,WA546770	12,800	143		143
32	SYSIMPTSTD,WA549226	4,970	143		143
33	SYSIMPTSTD,WA549419	52,400	143		143
34	SYSIMPTSTD,WA551476	(1,328)	143		143
35	SYSIMPTSTD,WA571836	(2,023)	143		143
36	SYSIMPTSTD,WA571837	(2,017)	143		143
37	SYSIMPTSTD,WA574357	15,574	143		143
38	SYSIMPTSTD,WA574418	(2,033)	143		143
39	SYSIMPTSTD,WA574485	(2,036)	143		143
40	SYSIMPTSTD,WA574522	(4,065)	143		143

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	SYSIMPTSTD,WA574523	(4,077)	143		143
23	SYSIMPTSTD,WA574525	(4,077)	143		143
24	SYSIMPTSTD,WA574690	11	143		143
25	SYSIMPTSTD,WA574721	(2,020)	143		143
26	SYSIMPTSTD,WA574749	(2,012)	143		143
27	SYSIMPTSTD,WA574775	(4,077)	143		143
28	SYSIMPTSTD,WA574782	(2,030)	143		143
29	SYSIMPTSTD,WA574816	(2,011)	143		143
30	SYSIMPTSTD,WA574818	(682)	143		143
31	SYSIMPTSTD,WA574838	(2,030)	143		143
32	SYSIMPTSTD,WA574842	(2,038)	143		143
33	SYSIMPTSTD,WA594256	106	143		143
34	SYSIMPTSTD,WA594257	(484)	143		143
35	SYSIMPTSTD,WA596156	6,943	143		143
36	SYSIMPTSTD,WA603482	349	143		143
37	SYSIMPTSTD,WA604606	1,264	143		143
38	SYSIMPTSTD,WA606554	(383)	143		143
39	SYSIMPTSTD,WA606616	(2,157)	143		143
40	SYSIMPTSTD,WA606634	(2,617)	143		143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	SYSIMPTSTD,WA606635	(2,428)	143		143
23	SYSIMPTSTD,WA606636	(2,428)	143		143
24	SYSIMPTSTD,WA606637	(2,428)	143		143
25	SYSIMPTSTD,WA606835	(1,062)	143		143
26	SYSIMPTSTD,WA606863	(3,191)	143	(500,000)	143
27	SYSIMPTSTD,WA606864	(851)	143	(250,000)	143
28	SYSIMPTSTD,WA606865	(2,693)	143	(500,000)	143
29	SYSIMPTSTD,WA606866	(2,245)	143	(500,000)	143
30	SYSIMPTSTD,WA606867	56	143	(160,000)	143
31	SYSIMPTSTD,WA606868	(2,347)	143	(500,000)	143
32	SYSIMPTSTD,WA606869	961	143	(250,000)	143
33	SYSIMPTSTD,WA606871	(1,708)	143	(250,000)	143
34	SYSIMPTSTD,WA606872	2,902	143	(160,000)	143
35	SYSIMPTSTD,WA606891	(2,644)	143	(500,000)	143
36	SYSIMPTSTD,WA606892	994	143	(250,000)	143
37	SYSIMPTSTD,WA606894	(223)	143	(250,000)	143
38	SYSIMPTSTD,WA606909	(1,396)	143	(500,000)	143
39	SYSIMPTSTD,WA606911	(2,811)	143	(500,000)	143
40	SYSIMPTSTD,WA606912	(2,625)	143	(500,000)	143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	SYSIMPTSTD,WA606914	834	143	(250,000)	143
23	SYSIMPTSTD,WA606915	(1,958)	143	(500,000)	143
24	SYSIMPTSTD,WA618021	(68)	143	(25,000)	143
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Compensation	35,805,942		various		35,805,942
2	Amortize through 2036					
3						
4	Capital Contribution on Phoenix Mead Transmission	9,629,186		108	83,010	9,546,176
5	U 1345 90 269 Amortize through 2050					
6						
7	Income Taxes AFUDC Equity	166,288,561				166,288,561
8	E 01345A 03 0437 Amortize through 2051		4,828,753	283,410.1	2,668,688	2,160,065
9						
10	AG 1 Deferral	2,019,323		407.3	696,750	1,322,573
11	E 01345A 11 0224 Amortize through 2022					
12						
13	Deferred Fuel and Purchased Power	228,608,518	83,695,789	various	11,391,874	300,912,433
14	E 01345A 03 0437, E 01345A 05 0816, 0826, 0827					
15	Amortize through 2022					
16						
17	Deferred Fuel and Purchased Power Mark to Market	3,728,079		547,555	3,728,079	
18	E 01345A 03 0437, E 01345A 05 0816, 0826, 0827					
19	Amortize through 2024					
20						
21	Deferred Fuel and Purchased Power Interest	45,575	87,119			132,694
22	E 01345A 03 0437, E 01345A 05 0816, 0826, 0827					
23	Amortize through 2022					
24						
25	Navajo Coal Reclamation	17,800,134		501	267,000	17,533,134
26	E 01345A 08 0172 Amortize through 2026					
27						
28	Pension and Other Postretirement Benefits	467,422,640	31,259,583	various	2,310,075	496,372,148
29	E 01345A 08 0172					
30						
31	Income Taxes Change in Rates	1,001,684	320			1,002,004
32	Amortize through 2050					
33						
34	Income Taxes Medicare Subsidy	4,861,267		283,410.1	459,642	4,401,625
35	Amortize through 2024					
36						
37	Income Taxes Investment Tax Credit Basis Adjustmt	25,333,862		283,410.1	414,237	24,919,625
38	E 01345A 16 0036 Amortize through 2049					
39						
40	Property Tax Deferral	56,053,490		408	2,142,342	53,911,148
41	E 01345A 11 0224 Amortize thorugh 2027					
42						
43						
44	TOTAL	1,455,031,814	160,640,504		41,175,520	1,574,496,798

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Lost Fixed Cost Recovery	45,904,819	14,835,871	400	7,653,892	53,086,798
2	E 01345A 11 0224					
3	Amortize through 2022					
4						
5	Retired Power Plant Costs	135,350,262		various	7,045,155	128,305,107
6	Amortize through 2033					
7						
8	Four Corners Cost Deferral	30,132,539		407	2,019,146	28,113,393
9	Amortize through 2024					
10						
11	SCR Deferral	88,044,302	7,126,945			95,171,247
12	E 01345A 16 0036					
13						
14	TCA Balancing account		1,902,919			1,902,919
15	E 01345A 16 0036 Amortize through 2023					
16						
17	Deficient Deferred Income Taxes	2,862,871		283/410.1	27,972	2,834,899
18	Tax Cuts & Jobs Act ACC					
19	Portion to be Amortized through 2046					
20						
21	Deficient Deferred Income Taxes	9,028,534		283/410.1	198,430	8,830,104
22	Tax Cuts & Jobs Act FERC					
23	Amortize through 2058					
24						
25	Tax Expense Adjustor Mechanism	5,853,692	2,102,006			7,955,698
26	Amortize through 2021					
27						
28	Ocotillo Deferral	110,819,593	14,099,890			124,919,483
29	E 01345A 16 0036					
30						
31	Demand Side Management	7,267,713	1,309			7,269,022
32	Amortize through 2022					
33						
34	Customer bill relief deferral	1,100,000	700,000			1,800,000
35	E 00000A 19 128					
36						
37	EIS Balancing Account	68,780		407.4	68,780	
38	Amortize through 2022					
39						
40	Spent Nuclear Fuel Storage	448		518	448	
41	E 01345A 03 0437, E 01345A 05 0816, 0826,					
42	0827 Amortize through 2027					
43						
44	TOTAL	1,455,031,814	160,640,504		41,175,520	1,574,496,798

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 232 Line No.: 1 Column: d

131,174,224

Schedule Page: 232 Line No.: 13 Column: d

411.8,555,547,502,411.9

Schedule Page: 232 Line No.: 28 Column: d

128, 228.3, 926

Schedule Page: 232.1 Line No.: 5 Column: d

403, 404, 407

Schedule Page: 232.1 Line No.: 17 Column: e

Deficient Deferred Income Taxes – Tax Cuts and Jobs Act-ACC: Amount Amortized to Income Tax Expense Account 410.1: $21,054

Schedule Page: 232.1 Line No.: 21 Column: e

Deficient Deferred Income Taxes Tax Cuts and Jobs Act-FERC: Amount Amortized to Income Tax Expense Account 410.1: $149,358

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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Asset Retirement Obligations	519,014,566			48,885,420	567,899,986
2	FERC Order# 552					
3	Amortize through 2057					
4						
5	Spent Nuclear Fuel Storage	49,890,352	518	1,640,477	75,402	48,325,277
6	E 01345A 03 0437, E 01345A 05 0816, 0826,					
7	0827 Amortize through 2027					
8						
9	Income Taxes Unamortized Investment Tax Credit	50,738,382	190	830,477		49,907,905
10	E 01345A 05 0816, 0826, 0827					
11	Amortize through 2049					
12						
13	Sundance Maintenance	14,777,503	553	2,311,284	402,300	12,868,519
14	E 01345A 05 0816, 0826, 0827					
15	Amortize through 2031					
16						
17	Income Tax Change in Rates	70,215,016	190/410.1	1,054,852		69,160,164
18	Amortize through 2047					
19						
20	Renewable Energy Standard	34,490,385	549	21,941,786	18,116,215	30,664,814
21	E 01345A 03 0437, E 01345A 05 0816, 0826,					
22	0827 Amortize through 2022					
23						
24	Demand Side Management	13,795,993	908	9,849,575	11,659,134	15,605,552
25	E 01345A 03 0437, E 01345A 05 0816, 0826, 0827					
26	Amortize through 2022					
27						
28	Other Postretirement Benefits	375,558,705	926.1	13,542,884		362,015,821
29	E 01345A 08 0172					
30						
31	Removal costs Cholla	14,530,020			221,392	14,751,412
32	Amortize through 2033					
33						
34	Removal costs Saguaro	10,951,492			116,155	11,067,647
35	Amortize through 2022					
36						
37	Property Tax Deferral	15,021,843			1,166,129	16,187,972
38	E01345A 11 0224					
39						
40						
41	TOTAL	2,571,086,529		68,114,347	175,398,799	2,678,370,981

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Four Corners Coal Reclamation	55,163,820	501	1,164,040	1,365,163	55,364,943
2	E 013454A 05 0816, 0826, 0827					
3	Amortize through 2038					
4						
5	Deferred Gain on Sale of Property	3,361,501	421.1	605,690		2,755,811
6	E 01345A 09 0357 Amortize through 2022					
7						
8	Excess Deferred Income Taxes	1,048,441,606	190/411.1	10,243,844		1,038,197,762
9	Tax Cuts & Jobs Act ACC					
10	Portion to be Amortized through 2046					
11						
12	Excess Deferred Income Taxes	244,957,954	190/411.1	2,893,344		242,064,610
13	Tax Cuts & Jobs Act FERC					
14	Amortize through 2058					
15						
16	Tax Expense Adjustor Mechanism	7,452,021	400	304,210		7,147,811
17	E 01345A 18 0003 Amortize through 2021					
18						
19	EIS Balancing Account	480,018	400	120,004	324,890	684,904
20	Amortize through 2023					
21						
22	TCA Balancing account	9,069,689			1,839,208	10,908,897
23	E 01345A 16 0036 Amortize through 2023					
24						
25	FERC Transmission True up	10,008,991	400	1,611,880	2,660,268	11,057,379
26	Amortize through 2023					
27						
28	Active Union Employee Medical Account	2,337,344			9,306	2,346,650
29	E 01345A 19 0236					
30						
31	Deferred Fuel and Purchased Power Mark to Market	20,829,328			88,557,817	109,387,145
32	E 01345A 03 0437, E 01345A 05 0816, 0826, 0827					
33	Amortize through 2024					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	2,571,086,529		68,114,347	175,398,799	2,678,370,981

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 278.1 Line No.: 8 Column: d

Excess Deferred Income Taxes – Tax Cuts & Jobs Act-ACC: Amount Amortized to Income Tax Expense Account 411.1: $7,710,541

Schedule Page: 278.1 Line No.: 12 Column: d

Excess Deferred Income Taxes Tax Cuts & Jobs Act-FERC: Amount Amortized to Income Tax Expense Account 411.1: $2,547,10

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	872,555,060	1,929,176,208
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	640,904,429	1,297,688,464
5	Large (or Ind.) (See Instr. 4)	84,795,700	168,994,809
6	(444) Public Street and Highway Lighting	10,024,557	19,293,027
7	(445) Other Sales to Public Authorities	53,048	121,141
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,608,332,794	3,415,273,649
11	(447) Sales for Resale	41,698,409	102,794,019
12	TOTAL Sales of Electricity	1,650,031,203	3,518,067,668
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,650,031,203	3,518,067,668
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,335	108,171
17	(451) Miscellaneous Service Revenues	1,518,073	2,809,347
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	384,983	1,531,046
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	3,250,386	3,310,358
22	(456.1) Revenues from Transmission of Electricity of Others	41,557,540	66,157,396
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	46,702,647	73,916,318
27	TOTAL Electric Operating Revenues	1,696,733,850	3,591,983,986

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
6,380,245	14,747,876	1,171,410	1,150,194	2
				3
5,887,758	12,223,505	135,261	133,874	4
1,048,943	2,248,560	3,070	3,231	5
53,490	122,752	1,299	1,266	6
747	1,714	132	138	7
				8
				9
13,371,183	29,344,407	1,311,172	1,288,703	10
1,093,797	3,088,308	34	49	11
14,464,980	32,432,715	1,311,206	1,288,752	12
				13
14,464,980	32,432,715	1,311,206	1,288,752	14

Line 12, column (b) includes $ 90,634,938 of unbilled revenues.
Line 12, column (d) includes 631,479 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 300 Line No.: 4 Column: b

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

Schedule Page: 300 Line No.: 4 Column: c

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

Schedule Page: 300 Line No.: 5 Column: b

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Schedule Page: 300 Line No.: 5 Column: c

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Schedule Page: 300 Line No.: 17 Column: b

Connection Charges	$ 1,471,022
Other	47,051
Total	$ 1,518,073

Schedule Page: 300 Line No.: 17 Column: c

Connection Charges	$ 2,790,720
Other	18,627
Total	$ 2,809,347

Schedule Page: 300 Line No.: 21 Column: b

PCS Project	$ 1,340,689
Bid Fee Proceeds	1,135,000
Management/Administration Fees	787,345
Fuel Loading	673,311
Facility Charges	278,824
Participant Station Power Revenue	68,095
Other	65,780
Surepay and Autopay Discount	(1,098,658)
Total	$ 3,250,386

Schedule Page: 300 Line No.: 21 Column: c

PCS Project	$ 2,688,999
Fuel Loading	1,257,366
Management/Administration Fees	631,466
Facility Charges	254,964
Bid Fee Proceeds	170,000
Participant Station Power Revenue	147,947
Other	137,402
Interconnection Study Fee	100,000
Surepay and Autopay Discount	(2,077,786)
Total	$ 3,310,358

Schedule Page: 300 Line No.: 1 Column: $

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

1440-100	Residential	61,722,601
1442-100	Commercial	27,334,161
1442-102	Industrial	1,545,752
1442-104	Irrigation	31,937
1444-100	Hwy lighting	487
1445-100	Other sales to public authorities	0
		90,634,938

Schedule Page: 300 Line No.: 1 Column: MWH

1440-100	Residential	438,994
1442-100	Commercial	184,511
1442-102	Industrial	7,557
1442-104	Irrigation	419
1444-100	Hwy lighting	(2)
1445-100	Other sales to public authorities	0
		631,479

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
1	1. POWER PRODUCTION AND OTHER SUPPLY EXPENSES	
2	Steam Power Generation Operation (500 509)	137,600,595
3	Steam Power Generation Maintenance (510 515)	39,136,570
4	Total Power Production Expenses Steam Power	176,737,165
5	Nuclear Power Generation Operation (517 525)	86,086,980
6	Nuclear Power Generation Maintenance (528 532)	17,921,940
7	Total Power Production Expenses Nuclear Power	104,008,920
8	Hydraulic Power Generation Operation (535 540.1)	
9	Hydraulic Power Generation Maintenance (541 545.1)	
10	Total Power Production Expenses Hydraulic Power	
11	Other Power Generation Operation (546 550.1)	233,629,694
12	Other Power Generation Maintenance (551 554.1)	24,716,114
13	Total Power Production Expenses Other Power	258,345,808
14	Other Power Supply Expenses	
15	Purchased Power (555)	116,419,777
16	System Control and Load Dispatching (556)	1,694,130
17	Other Expenses (557)	2,555,988
18	Total Other Power Supply Expenses (line 15 17)	112,169,659
19	Total Power Production Expenses (Total of lines 4, 7, 10, 13 and 18)	651,261,552
20	2. TRANSMISSION EXPENSES	
21	Transmission Operation Expenses	
22	(560) Operation Supervision and Engineering	638,119
23		
24	(561.1) Load Dispatch Reliability	1,821,181
25	(561.2) Load Dispatch Monitor and Operate Transmission System	1,817,401
26	(561.3) Load Dispatch Transmission Service and Scheduling	442,855
27	(561.4) Scheduling, System Control and Dispatch Services	1,325,247
28	(561.5) Reliability, Planning and Standards Development	1,185,098
29	(561.6) Transmission Service Studies	115
30	(561.7) Generation Interconnection Studies	43,479
31	(561.8) Reliability, Planning and Standards Development Services	412,821
32	(562) Station Expenses	391,701
33	(563) Overhead Line Expenses	762,171
34	(564) Underground Line Expenses	29,149
35	(565) Transmission of Electricity by Others	15,706,848
36	(566) Miscellaneous Transmission Expenses	5,819,448
37	(567) Rents	4,234,302
38	(567.1) Operation Supplies and Expenses (Non Major)	

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Document Accession #: 20210826-8022 Filed Date: 08/26/2021

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
39	TOTAL Transmission Operation Expenses (Lines 22 38)	34,629,935
40	Transmission Maintenance Expenses	
41	(568) Maintenance Supervision and Engineering	309,240
42	(569) Maintenance of Structures	539,444
43	(569.1) Maintenance of Computer Hardware	
44	(569.2) Maintenance of Computer Software	
45	(569.3) Maintenance of Communication Equipment	96,679
46	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	
47	(570) Maintenance of Station Equipment	2,263,999
48	(571) Maintenance Overhead Lines	1,265,170
49	(572) Maintenance of Underground Lines	70,887
50	(573) Maintenance of Miscellaneous Transmission Plant	3,383
51	(574) Maintenance of Transmission Plant	
52	TOTAL Transmission Maintenance Expenses (Lines 41 51)	4,548,802
53	Total Transmission Expenses (Lines 39 and 52)	39,178,737
54	3. REGIONAL MARKET EXPENSES	
55	Regional Market Operation Expenses	
56	(575.1) Operation Supervision	
57	(575.2) Day Ahead and Real Time Market Facilitation	304,863
58	(575.3) Transmission Rights Market Facilitation	
59	(575.4) Capacity Market Facilitation	
60	(575.5) Ancillary Services Market Facilitation	
61	(575.6) Market Monitoring and Compliance	
62	(575.7) Market Facilitation, Monitoring and Compliance Services	
63	Regional Market Operation Expenses (Lines 55 62)	304,863
64	Regional Market Maintenance Expenses	
65	(576.1) Maintenance of Structures and Improvements	
66	(576.2) Maintenance of Computer Hardware	
67	(576.3) Maintenance of Computer Software	
68	(576.4) Maintenance of Communication Equipment	
69	(576.5) Maintenance of Miscellaneous Market Operation Plant	
70	Regional Market Maintenance Expenses (Lines 65 69)	
71	TOTAL Regional Control and Market Operation Expenses (Lines 63,70)	304,863
72	4. DISTRIBUTION EXPENSES	
73	Distribution Operation Expenses (580 589)	32,528,256
74	Distribution Maintenance Expenses (590 598)	18,542,008
75	Total Distribution Expenses (Lines 73 and 74)	51,070,264

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Document Accession #: 20210826-8022 Filed Date: 08/26/2021

ELECTRIC CUSTOMER ACCOUNTS, SERVICE, SALES, ADMINISTRATIVE AND GENERAL EXPENSES

Report the amount of expenses for customer accounts, service, sales, and administrative and general expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)
1	(901 905) Customer Accounts Expenses	35,025,440
2	(907 910) Customer Service and Information Expenses	23,407,741
3	(911 917) Sales Expenses	6,989,364
4	8. ADMINISTRATIVE AND GENERAL EXPENSES	
5	Operations	
6	920 Administrative and General Salaries	56,512,317
7	921 Office Supplies and Expenses	1,383,035
8	(Less) 922 Administrative Expenses Transferred Credit	14,000,000
9	923 Outside Services Employed	24,236,064
10	924 Property Insurance	1,316,504
11	925 Injuries and Damages	4,355,703
12	926 Employee Pensions and Benefits	7,960,124
13	927 Franchise Requirements	
14	928 Regulatory Commission Expenses	9,921,359
15	(Less) 929 Duplicate Charges Credit	
16	930.1General Advertising Expenses	2,517,707
17	930.2Miscellaneous General Expenses	28,895,887
18	931 Rents	3,107,444
19	TOTAL Operation (Total of lines 6 thru 18)	52,494,122
20	Maintenance	
21	935 Maintenance of General Plant	6,605,108
22	TOTAL Administrative and General Expenses (Total of lines 19 and 21)	59,099,230

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Document Accession #: 20210826-8022 Filed Date: 08/26/2021

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Arizona Public Service Company	Arizona Public Service Company	Arizona Public Service Company	FNS
2	Arizona Public Service Company	Arizona Public Service Company	Arizona Public Service Company	FNS
3	Arizona Public Service Company	Arizona Public Service Company	Arizona Public Service Company	FNS
4	Ajo Improvement Company	N/A	N/A	FNO
5	City of Williams	N/A	N/A	FNO
6	Navajo Tribal Utility Authority	Tucson Electric Power	Navajo Tribal Utility Authority	FNO
7	Navopache Electric Cooperative, Inc.	N/A	N/A	FNO
8	Southwest Public Power Agency	N/A	N/A	FNO
9	TOUA	N/A	N/A	FNO
10	Broadview Energy JN LLC	N/A	N/A	LFP
11	Broadview Energy KW LLC	N/A	N/A	LFP
12	CSE Operating 1, LLC	N/A	N/A	LFP
13	El Cabo Wind	N/A	N/A	LFP
14	Electrical District 3	N/A	N/A	LFP
15	Grady Wind Center Energy, LLC	N/A	N/A	LFP
16	NOVO BioPower LLC	N/A	N/A	LFP
17	Public Service Company of New Mexico	N/A	N/A	LFP
18	Salt River Project	N/A	N/A	LFP
19	Trico Electric Cooperative Inc.	N/A	N/A	LFP
20	Tucson Electric Power Company	N/A	N/A	LFP
21	Tecolote Wind LLC	N/A	N/A	SFP
22	Duran Mesa LLC	N/A	N/A	SFP
23	Clines Corners Wind Farm LLC	N/A	N/A	SFP
24	Imperial Irrigation District Marketing	N/A	N/A	SFP
25	Mercuria Energy America LLC	N/A	N/A	SFP
26	Nevada Power Company	N/A	N/A	SFP
27	Powerex	N/A	N/A	SFP
28	Arizona Electric Power Cooperative, Inc	N/A	N/A	SFP
29	Avangrid Renewables, LLC	N/A	N/A	SFP
30	Brookfield Renewable Trading and Marketing	N/A	N/A	SFP
31	Dynasty Power Inc	N/A	N/A	SFP
32	EDF Trading North America, LLC	N/A	N/A	SFP
33	Guzman Power Markets LLC	N/A	N/A	SFP
34	Guzman Renewable Energy Partners	N/A	N/A	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Imperial Irrigation District Marketing	N/A	N/A	SFP
2	Macquarie Energy LLC	N/A	N/A	SFP
3	Mercuria Energy America LLC	N/A	N/A	SFP
4	PacifiCorp	N/A	N/A	SFP
5	Salt River Project	N/A	N/A	SFP
6	Tenaska Power Services Co.	N/A	N/A	SFP
7	Western Area Power Administration (DSW)	N/A	N/A	SFP
8	Mercuria Energy America LLC	N/A	N/A	SFP
9	Nevada Power Company	N/A	N/A	SFP
10	Western Area Power Administration (DSW)	N/A	N/A	SFP
11	Arizona Electric Power Cooperative, Inc	N/A	N/A	SFP
12	Arizona Public Service Company	N/A	N/A	SFP
13	Brookfield Renewable Trading and Marketing	N/A	N/A	SFP
14	CP Energy Marketing	N/A	N/A	SFP
15	DTE Energy Trading Inc	N/A	N/A	SFP
16	Dynasty Power Inc	N/A	N/A	SFP
17	EDF Trading North America, LLC	N/A	N/A	SFP
18	El Paso Electric Company	N/A	N/A	SFP
19	Exelon Generation Company, LLC	N/A	N/A	SFP
20	Guzman Power Markets LLC	N/A	N/A	SFP
21	Guzman Renewable Energy Partners	N/A	N/A	SFP
22	Imperial Irrigation District Marketing	N/A	N/A	SFP
23	Macquarie Energy LLC	N/A	N/A	SFP
24	Mag Energy Solutions, Inc	N/A	N/A	SFP
25	Mercuria Energy America LLC	N/A	N/A	SFP
26	Nevada Power Company	N/A	N/A	SFP
27	PacifiCorp	N/A	N/A	SFP
28	Powerex	N/A	N/A	SFP
29	Public Service Company of New Mexico	N/A	N/A	SFP
30	Rainbow Energy Marketing	N/A	N/A	SFP
31	Salt River Project	N/A	N/A	SFP
32	TEC Energy	N/A	N/A	SFP
33	Tenaska Power Services Co.	N/A	N/A	SFP
34	The Energy Authority Inc.	N/A	N/A	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

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4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	TransAlta Energy Marketing U.S. Inc.	N/A	N/A	SFP
2	Tucson Electric Power Company	N/A	N/A	SFP
3	Western Area Power Administration (DSW)	N/A	N/A	SFP
4	Guzman Power Markets LLC	N/A	N/A	NF
5	Mercuria Energy America LLC	N/A	N/A	NF
6	PacifiCorp	N/A	N/A	NF
7	Tenaska Power Services Co.	N/A	N/A	NF
8	Avangrid Renewables, LLC	N/A	N/A	NF
9	Black Hills Colorado Electric	N/A	N/A	NF
10	Black Hills Power Inc	N/A	N/A	NF
11	BP Energy Company	N/A	N/A	NF
12	Brookfield Energy Marketing LP	N/A	N/A	NF
13	CP Energy Marketing	N/A	N/A	NF
14	Dynasty Power Inc	N/A	N/A	NF
15	EDF Trading North America, LLC	N/A	N/A	NF
16	Exelon Generation Company, LLC	N/A	N/A	NF
17	Guzman Power Markets LLC	N/A	N/A	NF
18	Guzman Renewable Energy Partners	N/A	N/A	NF
19	Macquarie Energy LLC	N/A	N/A	NF
20	Mag Energy Solutions, Inc	N/A	N/A	NF
21	Mercuria Energy America LLC	N/A	N/A	NF
22	Morgan Stanley	N/A	N/A	NF
23	Nevada Power Company	N/A	N/A	NF
24	PacifiCorp	N/A	N/A	NF
25	Powerex	N/A	N/A	NF
26	Public Service Company of New Mexico	N/A	N/A	NF
27	Rainbow Energy Marketing	N/A	N/A	NF
28	Salt River Project	N/A	N/A	NF
29	Sempra Gas & Power Marketing, LLC	N/A	N/A	NF
30	Shell Energy North America LP	N/A	N/A	NF
31	TEC Energy	N/A	N/A	NF
32	Tenaska Power Services Co.	N/A	N/A	NF
33	The Energy Authority Inc.	N/A	N/A	NF
34	TransAlta Energy Marketing U.S. Inc.	N/A	N/A	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
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3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Tri State Generation and Transmission	N/A	N/A	NF
2	Tucson Electric Power Company	N/A	N/A	NF
3	WestConnect	N/A	N/A	NF
4	Yuma Cogeneration Associates	N/A	N/A	NF
5	Arizona Public Service Company	N/A	N/A	OLF
6	PacifiCorp	N/A	N/A	OLF
7	Public Service Company of New Mexico	N/A	N/A	OLF
8	Yuma Cogeneration Associates	Yuma Cogeneration Assoc.	San Diego Gas and Elect.	OLF
9	Imperial Irrigation District	N/A	N/A	OS
10	Luke AFB Main Field	DOE WAPA Lower	Luke Air Force Base	OS
11	Marine Corps. Air Station	DOE WAPA Lower	Marine Corps Air Station	OS
12	NOVO BioPower LLC	N/A	N/A	OS
13	Salt River Project (Schedule F)	N/A	N/A	OS
14	Salt River Project (Schedule Q)	Pinnacle Peak	Ocotillo 230	OS
15	Unit B Irrigation and Drainage District	N/A	N/A	OS
16	Yuma Mesa Irrigation and Drainage District	DOE WAPA Lower	Yuma Mesa Irrigation Dist	OS
17	Navajo Transitional Energy Company, LLC	N/A	N/A	OS
18	Other	Not Available	Not Available	AD
19				
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	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
OATT	Various	Various		7,822,195	7,822,195	1
OATT	Various	Various				2
OATT	Various	Various				3
OATT	Various	Various	3	2,964	2,964	4
OATT	Various	Various	8	10,738	10,738	5
OATT	Various	Various	8	12,662	12,662	6
OATT	Various	Various	60	51,095	51,095	7
OATT	Various	Various	150	275,977	275,977	8
OATT	Various	Various	13	12,560	12,560	9
OATT	Various	Various	167	192,696	192,696	10
OATT	Various	Various	130	151,771	151,771	11
OATT	Various	Various	1	1,972	1,972	12
OATT	Various	Various	300	301,953	301,953	13
OATT	Various	Various	90	79,497	79,497	14
OATT	Various	Various	200	237,782	237,782	15
OATT	Various	Various	14	26,984	26,984	16
OATT	Various	Various	145	31,275	31,275	17
OATT	Various	Various	127	77,364	77,364	18
OATT	Various	Various	2	4,344	4,344	19
OATT	Various	Various	110	36,600	36,600	20
OATT	Various	Various				21
OATT	Various	Various				22
OATT	Various	Various				23
OATT	Various	Various	80	17,436	17,436	24
OATT	Various	Various	50	1,039	1,039	25
OATT	Various	Various	25	11,937	11,937	26
OATT	Various	Various	224	107,225	107,225	27
OATT	Various	Various	15	360	360	28
OATT	Various	Various	1,077	10,981	10,981	29
OATT	Various	Various	60	1,840	1,840	30
OATT	Various	Various	75	1,200	1,200	31
OATT	Various	Various	75	1,249	1,249	32
OATT	Various	Various	100	2,400	2,400	33
OATT	Various	Various	10	240	240	34
			175,089	**14,635,736**	**14,635,736**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
OATT	Various	Various	27	432	432	1
OATT	Various	Various	57	800	800	2
OATT	Various	Various	175	1,760	1,760	3
OATT	Various	Various	4,048	69,792	69,792	4
OATT	Various	Various	725	4,830	4,830	5
OATT	Various	Various	390	7,249	7,249	6
OATT	Various	Various	280	6,412	6,412	7
OATT	Various	Various	3	329	329	8
OATT	Various	Various	100	7,156	7,156	9
OATT	Various	Various	35	5,880	5,880	10
OATT	Various	Various	1,161	1,206	1,206	11
OATT	Various	Various	5,004	4,980	4,980	12
OATT	Various	Various	200	400	400	13
OATT	Various	Various	761	458	458	14
OATT	Various	Various				15
OATT	Various	Various	1,365	1,340	1,340	16
OATT	Various	Various	1,440	811	811	17
OATT	Various	Various	1	1	1	18
OATT	Various	Various				19
OATT	Various	Various	5,283	9,640	9,640	20
OATT	Various	Various	2,054	3,399	3,399	21
OATT	Various	Various	1,028	1,008	1,008	22
OATT	Various	Various	2,557	2,418	2,418	23
OATT	Various	Various	1,957	337	337	24
OATT	Various	Various	660	144	144	25
OATT	Various	Various	1,900	2,000	2,000	26
OATT	Various	Various	12,885	21,283	21,283	27
OATT	Various	Various	785	785	785	28
OATT	Various	Various	5,355	1,519	1,519	29
OATT	Various	Various	1,586	1,673	1,673	30
OATT	Various	Various	20,528	10,417	10,417	31
OATT	Various	Various	57			32
OATT	Various	Various	55,334	56,420	56,420	33
OATT	Various	Various	64	64	64	34
			175,089	**14,635,736**	**14,635,736**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
OATT	Various	Various	550	1,482	1,482	1
OATT	Various	Various	1,800	592	592	2
OATT	Various	Various	448	376	376	3
OATT	Various	Various	25	560	560	4
OATT	Various	Various	2	22	22	5
OATT	Various	Various	175			6
OATT	Various	Various	10			7
OATT	Various	Various	305	500	500	8
OATT	Various	Various	350	1,538	1,538	9
OATT	Various	Various	1,305	1,305	1,305	10
OATT	Various	Various	60	60	60	11
OATT	Various	Various				12
OATT	Various	Various	25	25	25	13
OATT	Various	Various	1,848	1,785	1,785	14
OATT	Various	Various	15	21	21	15
OATT	Various	Various	325	325	325	16
OATT	Various	Various	5,366	3,348	3,348	17
OATT	Various	Various	815	1,051	1,051	18
OATT	Various	Various	200	200	200	19
OATT	Various	Various	5,480	2,195	2,195	20
OATT	Various	Various	1,341	1,405	1,405	21
OATT	Various	Various	500	500	500	22
OATT	Various	Various	100			23
OATT	Various	Various	2,231	2,281	2,281	24
OATT	Various	Various	1,383	875	875	25
OATT	Various	Various	984	1,377	1,377	26
OATT	Various	Various	1,692	1,206	1,206	27
OATT	Various	Various	308	250	250	28
OATT	Various	Various	406			29
OATT	Various	Various	2,361	1,526	1,526	30
OATT	Various	Various	611	404	404	31
OATT	Various	Various	1,927	2,190	2,190	32
OATT	Various	Various	1,641	1,251	1,251	33
OATT	Various	Various	5,817	8,268	8,268	34
			175,089	**14,635,736**	**14,635,736**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
OATT	Various	Various				1
OATT	Various	Various	3,210	3,270	3,270	2
OATT	Various	Various		59,404	59,404	3
OATT	Various	Various	168	52	52	4
RS 183	N/A	N/A		1,761,336	1,761,336	5
RS 183	N/A	N/A		462,863	462,863	6
RS 73	Palo Verde	Four Corners	130	176,641	176,641	7
RS 198	Riverside Substation	North Gila Sub	51	9,634	9,634	8
OATT	N/A	N/A				9
RS 162	Pinnacle Peak Sub	Luke Substation				10
RS 166	Gila Substation	Marine Corps Air Stn				11
OATT	N/A	N/A				12
RS 3	N/A	N/A		2,414,339	2,414,339	13
RS 3	Pinnacle Peak	Ocotillo 230				14
RS 181	Gila Substation	District Customer				15
RS 31	Gila Substation	Yuma Mesa Load				16
RS 291	N/A	N/A				17
Not Available	Not Available	Not Available				18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			175,089	**14,635,736**	**14,635,736**	

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
		60,491,002	60,491,002	2
		60,491,002	60,491,002	3
25,020	1,237	35	26,222	4
71,447	4,002	16,118	91,567	5
74,699	3,775	13,058	91,532	6
557,834		1,866	555,968	7
1,365,675	88,647	1,858,585	3,312,907	8
118,331	5,943	1,434	125,708	9
1,582,341		4,169	1,578,172	10
1,231,763		3,235	1,228,528	11
9,475	298	1,029	10,802	12
2,842,529		6,365	2,836,164	13
852,871		2,108	850,763	14
1,895,019		4,601	1,890,418	15
132,669		515	132,154	16
1,373,889		2,434	1,371,455	17
1,203,417			1,203,417	18
18,950		79	18,871	19
1,042,397		1,184	1,041,213	20
		104,802	104,802	21
		40,491	40,491	22
		95,274	95,274	23
552,160			552,160	24
245,105			245,105	25
122,553			122,553	26
1,110,870		2	1,110,868	27
2,885			2,885	28
198,913			198,913	29
14,173			14,173	30
14,423			14,423	31
14,206			14,206	32
19,230			19,230	33
1,054			1,054	34
207,590,209	**201,813,1**	**17,837,92**	**225,573,2**	

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
5,192			5,192	1
10,188			10,188	2
33,784			33,784	3
890,038			890,038	4
139,418			139,418	5
77,884			77,884	6
52,762			52,762	7
2,214			2,214	8
113,072			113,072	9
39,575			39,575	10
11,426		10	11,416	11
43,904			43,904	12
1,753			1,753	13
8,026			8,026	14
				15
9,162			9,162	16
11,298		27	11,271	17
12			12	18
				19
68,352		131	68,221	20
24,310		573	23,737	21
12,238			12,238	22
32,159			32,159	23
3,637		253	3,384	24
4,966			4,966	25
15,563			15,563	26
179,236			179,236	27
5,168			5,168	28
11,351		241	11,110	29
25,783			25,783	30
258,611			258,611	31
685			685	32
347,232		1,109	346,123	33
502			502	34
2075907209	**20173, 1**	**17, 837, 92**	**2275, 573, 2**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
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11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
10,905		103	10,802	1
20,127			20,127	2
3,787			3,787	3
2,534			2,534	4
251			251	5
17,738			17,738	6
1,255			1,255	7
3,481			3,481	8
2,740			2,740	9
6,511			6,511	10
452			452	11
				12
110			110	13
10,784			10,784	14
207			207	15
2,547		7	2,540	16
38,301			38,301	17
7,246			7,246	18
1,508			1,508	19
38,420			38,420	20
16,966		3	16,963	21
4,076			4,076	22
754			754	23
13,045			13,045	24
10,425			10,425	25
11,180			11,180	26
8,544			8,544	27
2,322			2,322	28
3,060			3,060	29
16,629		14	16,615	30
5,295			5,295	31
16,119			16,119	32
12,861		6	12,855	33
60,532			60,532	34
207,590,209	201,813,1	17,837,92	225,573,2	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
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11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		4	4	1
29,225			29,225	2
164,254			164,254	3
2,022			2,022	4
				5
				6
353,758			353,758	7
489,574			489,574	8
		13,249	13,249	9
43,362	321		43,683	10
19,413			19,413	11
		679	679	12
3,230			3,230	13
		233,996	233,996	14
135			135	15
1,125			1,125	16
	97,148	7,776	104,924	17
		573,625	573,625	18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
207,590,209	**201,318,1**	**17,837,92**	**225,573,2**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: a

Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 1 Column: c

Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 1 Column: h

Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 1 Column: m

AzISA Fees, Unreserved Use Penalty, and Unreserved Use Credit

Schedule Page: 328 Line No.: 2 Column: a

Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 2 Column: c

Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 3 Column: a

Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 3 Column: c

Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 4 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 5 Column: m

Direct Assignment Charges and Unreserved Use Credit

Schedule Page: 328 Line No.: 6 Column: m

Direct Assignment Charges and Unreserved Use Credit

Schedule Page: 328 Line No.: 7 Column: m

Direct Assignment Charges and Unreserved Use Credit

Schedule Page: 328 Line No.: 8 Column: m

Direct Assignment Charges and Unreserved Use Credit

Schedule Page: 328 Line No.: 9 Column: m

Direct Assignment Charges and Unreserved Use Credit

Schedule Page: 328 Line No.: 10 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 11 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 12 Column: m

Direct Assignment Charges and Unreserved Use Credit

Schedule Page: 328 Line No.: 13 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 14 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 15 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 16 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 17 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 19 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 20 Column: m

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

Unreserved Use Credit

Schedule Page: 328 Line No.: 21 Column: h

Monthly Demand Service Period

Schedule Page: 328 Line No.: 21 Column: m

Charge equivalent to SFP monthly charge for long-term transmission contract deferral, recognized over deferral period

Schedule Page: 328 Line No.: 22 Column: h

Monthly Demand Service Period

Schedule Page: 328 Line No.: 22 Column: m

Charge equivalent to SFP monthly charge for long-term transmission contract deferral, recognized over deferral period

Schedule Page: 328 Line No.: 23 Column: h

Monthly Demand Service Period

Schedule Page: 328 Line No.: 23 Column: m

Charge equivalent to SFP monthly charge for long-term transmission contract deferral, recognized over deferral period

Schedule Page: 328 Line No.: 24 Column: h

Monthly Demand Service Period

Schedule Page: 328 Line No.: 25 Column: h

Monthly Demand Service Period

Schedule Page: 328 Line No.: 26 Column: h

Monthly Demand Service Period

Schedule Page: 328 Line No.: 27 Column: h

Monthly Demand Service Period

Schedule Page: 328 Line No.: 27 Column: m

Unreserved Use Credit

Schedule Page: 328 Line No.: 28 Column: h

Daily Demand Service Period

Schedule Page: 328 Line No.: 29 Column: h

Daily Demand Service Period

Schedule Page: 328 Line No.: 30 Column: h

Daily Demand Service Period

Schedule Page: 328 Line No.: 31 Column: h

Daily Demand Service Period

Schedule Page: 328 Line No.: 32 Column: h

Daily Demand Service Period

Schedule Page: 328 Line No.: 33 Column: h

Daily Demand Service Period

Schedule Page: 328 Line No.: 34 Column: h

Daily Demand Service Period

Schedule Page: 328.1 Line No.: 1 Column: h

Daily Demand Service Period

Schedule Page: 328.1 Line No.: 2 Column: h

Daily Demand Service Period

Schedule Page: 328.1 Line No.: 3 Column: h

Daily Demand Service Period

Schedule Page: 328.1 Line No.: 4 Column: h

Daily Demand Service Period

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

Schedule Page: 328.1 Line No.: 5 Column: h
Daily Demand Service Period

Schedule Page: 328.1 Line No.: 6 Column: h
Daily Demand Service Period

Schedule Page: 328.1 Line No.: 7 Column: h
Daily Demand Service Period

Schedule Page: 328.1 Line No.: 8 Column: h
Weekly Demand Service Period

Schedule Page: 328.1 Line No.: 9 Column: h
Weekly Demand Service Period

Schedule Page: 328.1 Line No.: 10 Column: h
Weekly Demand Service Period

Schedule Page: 328.1 Line No.: 11 Column: h
Weekly Demand Service Period

Schedule Page: 328.1 Line No.: 11 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 12 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 13 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 14 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 15 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 16 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 17 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 17 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 18 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 19 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 20 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 20 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 21 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 21 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 22 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 23 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 24 Column: h
Hourly Demand Service Period

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	08/26/2021	2021/Q2

FOOTNOTE DATA

Schedule Page: 328.1 Line No.: 24 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 25 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 26 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 27 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 28 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 29 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 29 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 30 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 30 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 31 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 32 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 33 Column: h
Hourly Demand Service Period

Schedule Page: 328.1 Line No.: 33 Column: m
Unreserved Use Credit

Schedule Page: 328.1 Line No.: 34 Column: h
Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 1 Column: h
Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 1 Column: m
Unreserved Use Credit

Schedule Page: 328.2 Line No.: 2 Column: h
Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 3 Column: h
Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 4 Column: h
Daily Demand Service Period

Schedule Page: 328.2 Line No.: 5 Column: h
Daily Demand Service Period

Schedule Page: 328.2 Line No.: 6 Column: h
Daily Demand Service Period

Schedule Page: 328.2 Line No.: 7 Column: h
Daily Demand Service Period

Schedule Page: 328.2 Line No.: 8 Column: h
Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 9 Column: h
Hourly Demand Service Period

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FOOTNOTE DATA

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Hourly Demand Service Period
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Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 12 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 13 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 14 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 15 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 16 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 16 Column: m
Unreserved Use Credit
Schedule Page: 328.2 Line No.: 17 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 18 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 19 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 20 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 21 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 21 Column: m
Unreserved Use Credit
Schedule Page: 328.2 Line No.: 22 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 23 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 24 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 25 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 26 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 27 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 28 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 29 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 30 Column: h
Hourly Demand Service Period
Schedule Page: 328.2 Line No.: 30 Column: m
Unreserved Use Credit

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FOOTNOTE DATA

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Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 32 Column: h

Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 33 Column: h

Hourly Demand Service Period

Schedule Page: 328.2 Line No.: 33 Column: m

Unreserved Use Credit

Schedule Page: 328.2 Line No.: 34 Column: h

Hourly Demand Service Period

Schedule Page: 328.3 Line No.: 1 Column: h

Hourly Demand Service Period

Schedule Page: 328.3 Line No.: 1 Column: m

Unreserved Use Credit

Schedule Page: 328.3 Line No.: 2 Column: h

Hourly Demand Service Period

Schedule Page: 328.3 Line No.: 3 Column: h

Hourly Demand Service Period

Schedule Page: 328.3 Line No.: 4 Column: h

Hourly Demand Service Period

Schedule Page: 328.3 Line No.: 5 Column: h

Exchange agreement pursuant to Pre888 contract

Schedule Page: 328.3 Line No.: 6 Column: h

Exchange agreement pursuant to Pre888 contract

Schedule Page: 328.3 Line No.: 9 Column: m

Direct Assignment Charges

Schedule Page: 328.3 Line No.: 10 Column: h

Part of APS NITS load - recovery of transmission cost contract

Schedule Page: 328.3 Line No.: 11 Column: h

Part of APS NITS load - recovery of transmission cost contract

Schedule Page: 328.3 Line No.: 12 Column: m

Direct Assignment Charges

Schedule Page: 328.3 Line No.: 13 Column: h

Part of APS NITS load - recovery of transmission cost contract

Schedule Page: 328.3 Line No.: 14 Column: m

Direct Assignment Charges

Schedule Page: 328.3 Line No.: 15 Column: h

Part of APS NITS load - recovery of transmission cost contract

Schedule Page: 328.3 Line No.: 16 Column: h

Part of APS NITS load - recovery of transmission cost contract

Schedule Page: 328.3 Line No.: 17 Column: m

BA Services Administrative Fees

Schedule Page: 328.3 Line No.: 18 Column: m

FERC Transmission rate true up, change in estimate, and timing difference

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Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

Document Accession #: 20210826-8022 Filed Date: 08/26/2021

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO Firm Network Service for Others, FNS Firm Network Transmission Service for Self, LFP Long Term Firm Point to Point Transmission Service, OLF Other Long Term Firm Transmission Service, SFP Short Term Firm Point to Point Transmission Reservation, NF Non Firm Transmission Service, OS Other Transmission Service and AD Out of Period Adjustments. Use this code for any accounting adjustments or "true ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
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29					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt hours Received (c)	Magawatt hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	LFP			3,310			3,310
2	Bureau of Indian Affair	OLF			38,400			38,400
3	Department of Energy	OS	184,426	184,426		162,251	24,122	186,373
4	Department of Energy	NF	23,145	23,145	56,142	397	88,544	32,005
5	Department of Energy	FNS	87,375	87,375	324,133	162,234	143,390	342,977
6	Department of Energy	FNS	306,774	306,774	1,295,632	388,634	226,123	1,458,143
7	Department of Energy	LFP	111,149	111,149		155,837	62,984	92,853
8	Department of Energy	LFP						
9	Department of Energy	LFP	116,137	116,137	2,182,020	181,908	54,848	2,309,080
10	Department of Energy	OS			22,992			22,992
11	Electric District # 3	LFP	799	799	25,547		2,007	23,540
12	Electric District # 4	OLF	567	567	17,062		2,913	14,149
13	Salt River Project	FNS	9,148	9,148	45,364	19,078	18,958	45,484
14	Salt River Project	OLF	92,478	92,478	407,623	193,450	193,450	407,623
15	Salt River Project	LFP	26,620	26,620	527,301	29,955	223,199	334,057
16	Salt River Project	FNS	124,345	124,345	793,984	279,378	306,011	767,351
	TOTAL		1,661,575	1,661,575	6,670,629	2,169,035	2,241,161	6,598,503

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt hours Received (c)	Magawatt hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Salt River Project	OLF	34,806	34,806	62,903	78,208	85,538	55,573
2	Salt River Project	OS	475,406	475,406		271,260	254,615	16,645
3	Salt River Project	FNS	41,050	41,050	632,088	74,782	54,752	652,118
4	Southern Cal Edison	LFP	27	27	48,848		794	49,642
5	Southwest Transmission	SFP	22,963	22,963	113,212		177,299	64,087
6	Tucson Electric Power	NF						
7	Public Service Co of NM	NF						
8	SRP Misc AR	OS						
9	Navopache Electric Co	OS			80,688			80,688
10	Navopache Electric Co	OS	4,360	4,360		171,663	371,446	199,783
11								
12								
13								
14								
15								
16								
	TOTAL		1,661,575	1,661,575	6,670,629	2,169,035	2,241,161	6,598,503

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: a

Intercompany Transmission

Schedule Page: 332 Line No.: 1 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 2 Column: b

Terminates with 30 days notice

Schedule Page: 332 Line No.: 2 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 3 Column: b

Loss compensation on jointly owned facilities

Schedule Page: 332 Line No.: 3 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 4 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 5 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 6 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 7 Column: b

Terminates September 30, 2029

Schedule Page: 332 Line No.: 7 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 8 Column: b

Terminates May 1, 2022

Schedule Page: 332 Line No.: 8 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 9 Column: b

Terminates December 31, 2022

Schedule Page: 332 Line No.: 9 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 10 Column: b

Terminates September 30, 2029

Schedule Page: 332 Line No.: 10 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 11 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 12 Column: b

Effective until terminated by counterparty

Schedule Page: 332 Line No.: 12 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 13 Column: b

Terminates January 1, 2024

Schedule Page: 332 Line No.: 13 Column: g

Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.

Schedule Page: 332 Line No.: 14 Column: b

Terminates with 5 year notice

Schedule Page: 332 Line No.: 14 Column: g

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FOOTNOTE DATA

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 15 Column: b

Terminates May 1, 2023

Schedule Page: 332 Line No.: 15 Column: g

Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.

Schedule Page: 332 Line No.: 16 Column: g

Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.

Schedule Page: 332 Line No.: 16 Column: h

APS payment as a credit on APS provides SRP in the same contract

Schedule Page: 332.1 Line No.: 1 Column: b

Terminates with 1 year notice

Schedule Page: 332.1 Line No.: 1 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 2 Column: b

Loss compensation for deliveries to DV

Schedule Page: 332.1 Line No.: 2 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 3 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 4 Column: b

Terminates September 30, 2037

Schedule Page: 332.1 Line No.: 4 Column: g

Ancillary/Timing

Schedule Page: 332.1 Line No.: 5 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 6 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 7 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 8 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 9 Column: b

Navopache Vernon Tie Facilities use charges

Schedule Page: 332.1 Line No.: 9 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 10 Column: g

Prior period adjustment /Timing

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Document Accession #: 20210826-8022 Filed Date: 08/26/2021

Depreciation, Depletion and Amortization of Electric Plant (Accts 403, 403.1, 404, and 405) (Except Amortization of Acquisition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Functional Classification	Depreciation Expense (Account 403)	Depreciation Expense for Asset Retirement Costs (Account 403.1)	Amortization of Other Limited Term Electric Plant (Account 404)	Amortization of Other Electric Plant (Account 405)	Total
	(a)	(b)	(c)	(e)	(e)	(f)
1	Intangible Plant			37,439,417		37,439,417
2	Steam Production Plant	41,060,676	2,277,365	1,777		43,339,818
3	Nuclear Production Plant	15,337,033	(376,143)	2,701,351		17,662,241
4	Hydraulic Production Plant Conv					
5	Hydraulic Production Plant Pumped Storage					
6	Other Production Plant	64,290,782	557,238			64,848,020
7	Transmission Plant	30,645,690		3,843,840		34,489,530
8	Distribution Plant	81,133,018		609,947		81,742,965
9	General Plant	32,181,121		3,989,311		36,170,432
10	Common Plant					
11	TOTAL ELECTRIC (lines 2 through 10)	264,648,320	2,458,460	48,585,643		315,692,423

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	08/26/2021	End of 2021/Q2

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AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	12,519,220	22,974,402		
3	Net Sales (Account 447)	(12,197,365)	(20,641,165)		
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	CAISO Non Purchases (Account 555)	2,199,497	3,424,877		
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
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40					
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44					
45					
46	TOTAL	2,521,352	5,758,114		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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MONTHLY PEAKS AND OUTPUT

(1) (1) Report the monthly peak load and energy output. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non integrated system. In quarter 1 report January, February, and March only. In quarter 2 report April, May, and June only. In quarter 3 report July, August, and September only.
(2) Report on column (b) by month the system's output in Megawatt hours for each month.
(3) Report on column (c) by month the non requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on columns (e) and (f) the specified information for each monthly peak load reported on column (d).
(6) Report Monthly Peak Hours in military time; 0100 for 1:00 AM, 1200 for 12 AM, and 1830 for 6:30 PM, etc.

NAME OF SYSTEM: Arizona Public Service Company

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
1	January	2,433,477	194,939	4,213	27	8
2	February	2,024,922	175,256	3,708	19	8
3	March	2,323,076	284,178	3,730	1	8
4	Total	6,781,475	654,373	11,651		
5	April	2,244,996	117,367	4,451	30	18
6	May	2,637,261	94,219	5,193	31	18
7	June	3,677,709	263,990	7,575	18	18
8	Total	8,559,966	475,576	17,219		
9	July				0	0
10	August				0	0
11	September				0	0
12	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Arizona Public Service Company

Line No.	Month (a)	Monthly Peak MW Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long Term Firm Point to point Reservations (g)	Other Long Term Firm Service (h)	Short Term Firm Point to point Reservation (i)	Other Service (j)
1	January	5,857	27	8	4,261	129	1,286	181		
2	February	5,339	19	8	3,700	172	1,286	181		
3	March	5,363	1	8	3,717	179	1,286	181		
4	Total for Quarter 1				11,678	480	3,858	543		
5	April	6,036	30	18	4,385	184	1,286	181		
6	May	6,828	31	18	5,152	210	1,286	181		
7	June	9,269	18	18	7,548	254	1,286	181		
8	Total for Quarter 2				17,085	648	3,858	543		
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year				28,763	1,128	7,716	1,086		

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MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM: Arizona Public Service Company

Line No.	Month (a)	Monthly Peak MW Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point to Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

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APS SCHEDULE E-9
FERC FORM 1

Fiscal Year Ended
December 31, 2021

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Arizona Public Service Company	End of: 2021/ Q4

FERC FORM NO. 1 (REV. 02-04)

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
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The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to

questions-faqs-efilingferc-online.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Arizona Public Service Company	End of: 2021/ Q4

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
400 North 5th Street, Phoenix, AZ 85004

05 Name of Contact Person	06 Title of Contact Person
Barbara D. Lockwood	Senior VP, Public Policy

07 Address of Contact Person (Street, City, State, Zip Code)
400 North 5th Street, Phoenix, AZ 85004

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
(602) 250-3361	(1) ☑ An Original (2) ☐ A Resubmission	03/16/2022

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Elizabeth A. Blankenship	/s/Elizabeth A. Blankenship	03/16/2022
02 Title		
VP Controller & CAO APS/PNW		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
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	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	

29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
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43	Regional Transmission Service Revenues (Account 457.1)	302	
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45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
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49	Transmission of Electricity by ISO/RTOs	331	
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56	Common Utility Plant and Expenses	356	
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60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	

66	**Generating Plant Statistics Pages**	410	
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67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☑ No annual report to stockholders is prepared		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Theodore N. Geisler

Senior Vice President & Chief Financial Officer Senior Vice President & CFO

400 North 5th Street, Phoenix, AZ 85004

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: AZ

Date of Incorporation: 1920-02-06

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

State of Arizona - Class A Electric Utility

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

All of the outstanding shares of common stock of the Company are owned by Pinnacle West Capital Corporation (formerly AZP Group Inc.) which became the Company's corporate parent effective April 29, 1985 pursuant to a corporate restructuring. The corporate restructuring did not affect any of its outstanding debt securities, all of which remain obligations of the Company.
See Pinnacle West Capital Corporation's Annual Report on Form 10-K for the fiscal year ended December 31, 2021 as filed with the Securities and Exchange Commission.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Bixco, Inc.	Inactive	100	
2	APS Foundation, Inc.	A non-profit corporation which makes distributions to charitable organizations	100	(a) See Footnote
3	Axiom Power Solutions, Inc.	Inactive	100	
4	PWENewco, Inc.	Inactive	100	

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: FootnoteReferences
The APS Foundation is an Arizona non-profit corporation. The APS Foundation has no stockholders or members, and all voting power is held by the Board of Directors.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	[a] Chairman of the Board and Chief Executive Officer	Jeffrey B. Guldner	[i] 1,100,000		
2	[b] President and Chief Operating Officer	Daniel T. Froetscher	343,000		2021-08-31
3	[c] Chief Administrative Officer	James R. Hatfield	[g] 700,000	2021-08-30	2021-12-31
4	Executive Vice President and Chief Nuclear Officer	Maria L. Lacal	600,000		
5	[d] Executive Vice President, General Counsel and Chief Development Officer	Robert E. Smith	[h] 610,000	2021-06-23	
6	Senior Vice President, Human Resources	Donna M. Easterly	385,000		
7	Senior Vice President and Chief Financial Officer	Theodore N. Geisler	[j] 450,000		
8	Senior Vice President, Public Policy	Barbara D. Lockwood	385,000		
9	Vice President, Controller and Chief Accounting Officer	Elizabeth A. Blankenship	[f] 310,000		
10	Vice President, Treasurer	Andrew D. Cooper	[k] 320,000		
11	[e] Executive Vice President, Operations	Jacob Tetlow	428,000	2021-05-19	

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OfficerTitle

Mr. Guldner was appointed President of APS effective August 31, 2021. He kept all other titles.

(b) Concept: OfficerTitle

Mr. Froetscher retired effective August 31, 2021.

(c) Concept: OfficerTitle

Mr. Hatfield's title was changed to Advisor to the CEO on August 30, 2021 and retired effective December 31, 2021.

(d) Concept: OfficerTitle

Mr. Smith was appointed Executive Vice President and Chief Development Officer effective June 23, 2021, and retained title of General Counsel.

(e) Concept: OfficerTitle

Mr. Tetlow was appointed Executive Vice President, Operations of APS.

(f) Concept: OfficerSalary

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

(g) Concept: OfficerSalary

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

(h) Concept: OfficerSalary

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

(i) Concept: OfficerSalary

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

(j) Concept: OfficerSalary

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

(k) Concept: OfficerSalary

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Gylnis A. Bryan	Phoenix, Arizona		
2	Denis A. Cortese	Fountain Hills, Arizona		
3	Richard P. Fox	Scottsdale, Arizona		
4	[a] William Spence	Bethlehem, PA		
5	Jeffrey B. Guldner, Chairman and CEO	Phoenix, Arizona		
6	Dale E. Klein	Austin, Texas		
7	[b] Humberto S. Lopez	Tucson, Arizona		
8	Kathryn L. Munro	La Jolla, California		
9	Bruce J. Nordstrom	Flagstaff, Arizona		
10	Paula J. Sims	Chapel Hill, North Carolina		
11	James E. Trevathan, Jr.	Humble, Texas		
12	David P. Wagener	New York, New York		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector

Mr. Spence was appointed to the Board on February 26, 2021.

(b) Concept: NameAndTitleOfDirector

Mr. Lopez retired from the Board May 2021.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	FERC Electric Tariff, Volume 2	ER20-1317-003
2	FERC Electric Tariff, Volume 5	ER21-2577-000
3	FERC Electric Rate Schedule No. 182	ER21-655
4	[a] FERC Electric Tariff, Volume 6	ER13-1296

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber

Tariff Title updated to accurately reflect FERC.gov. The FERC Electric Tariff, Volume 6 (WestConnect Tariff) does not have any direct FERC Form No. 1 inputs. However, the relevant input to the WestConnect Tariff is APS's FERC Electric Tariff Volume 2 which does have FERC Form No. 1 inputs. Out of an abundance of caution, APS included the WestConnect Tariff on page 106 of the FERC Form No. 1.On December 15, 2020, a cancellation for FERC Electric Rate Schedule No. 182 was filed. The effective date of the cancellation is February 15, 2021. Previous FERC Proceeding Docket Number was ER11-3926.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	202110273123	10/27/2021	ER20-1317-003	[a] see footnote	FERC Electric Tariff, Volume 2

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfFiling
Compliance filing of FERC Formula Rate to be in Compliance with FERC Order No. 864. Original filing on 3/17/2020, as amended on 4/28/2020, 9/29/2021, and 10/27/2021

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1 None.

2 None.

3 None.

4

During quarter one:

Lease Extensions/Landlord Change:

Tuba City Office
Effective Date: 04/01/2021
Expiration Date: 03/31/2024
Length of Term: 3 years
Names of Parties: Pauline Denetsosie and Arizona Public Service Company
Rents: $1,584.08 per month plus tax
Name of commission authorizing the lease: Dale Benz, Mgr Corp Facility/Real Estate
Reference to authorization: LE-CA-PRD-0001 Commitment Authority and Signing Procedure

9th Street Print Shop Office
Effective Date: 04/01/2021
Expiration Date: 05/31/2024
Length of Term: 3 years
Names of Parties: 220 South 9th Street, LP (c/o VWP Realty, LLC) and Arizona Public Service Company
Rents: $9,115.52 per month plus tax
Name of commission authorizing the lease: Dale Benz, Mgr Corp Facility/Real Estate
Reference to authorization: LE-CA-PRD-0001 Commitment Authority and Signing Procedure

During quarter two: No Activity.

During quarter three:

Bunker Peak Substation Lease
Effective Date: August 1, 2021
Expiration Date: December 31, 2022
Length of Term: 16 months
Names of Parties: J & H Development and Arizona Public Service Company
Rents: $1,500 per month; $25,500 paid for entire lease
Name of commission authorizing the lease: APS Land Department
Reference to authorization: LE-CA-PRD-0001 Commitment Authority and Signing Procedure

Lease Extensions:
Prescott Business Office Lease
Effective Date: August 14, 2021
Expiration Date: December 21, 2021
Length of Term: 4 months
Names of Parties: Cortez Commercial LLC and Arizona Public Service Company
Rents: $816 per month
Name of commission authorizing the lease: Dale Benz, Mgr Corp Facility/Real Estate
Reference to authorization: LE-CA-PRD-0001 Commitment Authority and Signing Procedure

Kearny Business Office Lease
Effective Date: January 31, 2020
Length of Term: month-to-month while working on new lease terms with new owner
Names of Parties: Innovation Retail Center LLC and Arizona Public Service Company
Rents: $328.36 per month plus tax
Name of commission authorizing the lease: Dale Benz, Mgr Corp Facility/Real Estate
Reference to authorization: LE-CA-PRD-0001 Commitment Authority and Signing Procedure

During quarter four:

Lease Extension:

Prescott Business Office Lease
Effective Date: December 21, 2021
Length of Term: month-to-month
Names of Parties: Cortez Commercial LLC and Arizona Public Service Company
Rents: $816 per month
Name of commission authorizing the lease: Dale Benz, Mgr Corp Facility/Real Estate
Reference to authorization: LE-CA-PRD-0001 Commitment Authority and Signing Procedure

5

Distribution: No Activity in 2021.

Transmission

During quarter one:

North Gila – Orchard 230kV Line Circuit #1
Reason for addition: To increase the ability to import resources into the Yuma load pocket. The project will also be used to improve reliability, serve the need for electric energy, and provide continuity of service for the greater Yuma area by adding a transmission source in a new area of the Yuma system. This project will have double-circuit capability with one circuit in-service in 2021 and the second circuit in-service TBD.

Size

(a)	Voltage Class	230kV AC
(b)	Point of Origin	North Gila Substation
(c)	Point of Termination	Orchard 230kV Substation

(c)	Point of Transmission	Orchard 230kV Substation
(d)	Length	Approximately 13 miles

Date

(a)	Construction Start	2020 (i)
(b)	In Service	2021 (ii)

(i) Date shown as originally disclosed but has since been updated to 2021
(ii) Date shown as originally disclosed but has since been updated to 2022

Permitting / Siting Status
CEC issued 2/2/2012 (Case No. 163, Decision No. 72801). Note – North Gila to TS8 230kV Transmission Line is now referred to as North Gila – Orchard 230kV Line.

During quarter two:

AES 230kV Interconnection at Westwing 230kV Substation
Reason for addition: This will be a generator tie-line to connect the AES Battery Energy Storage Project to the Westwing 230kV Substation.

Size

(a)	Voltage Class	230kV AC
(b)	Point of Origin	AES: 200MW Battery Energy Storage Project
(c)	Point of Transmission	Westwing 230kV Substation
(d)	Length	Less than 1 mile

Date

(a)	Construction Start	2021 (i)
(b)	In Service	2022

(i) Date shown as originally disclosed but has since been updated to 2022

Permitting / Siting Status
An application for a CEC has not yet been filed. APS anticipates filing a CEC application in 2021.(ii)
(ii) Information shown as originally disclosed but has since been updated to

"On I1/5/2021, in Decision Nos. 78303 and 78304, the Commission granted CEC-I and CEC-2, respectively (Case No. 190). CEC-1 is for the portion of the Project that will be owned by APS and extends from Westwing substation to the Point of Demarcation (POD). The POD is outside the energy storage project. The companion CEC-2 is for the portion of the project from the POD to the energy storage project substation. At a later date, prior to construction, APS intends to transfer CEC-2 to the Interconnection Customer."

Hashknife Generation Tie Line Project
Reason for addition: This will be a generator tie-line to connect Hashknife Solar Project to the Cholla 500kV Substation.

Size

(a)	Voltage Class	500kV AC
(b)	Point of Origin	New substation interconnecting Hashknife Solar Project (i)
(c)	Point of Transmission	Cholla 500kV Substation
(d)	Length	Less than 1 mile

Date

(a)	Construction Start	2021 (ii)
(b)	In Service	2022 (iii)

(i) Information shown as originally disclosed but has since been updated to "Hashknife Energy Center project substation"
(ii) Date shown as originally disclosed but has since been updated to 2022
(iii) Date shown as originally disclosed but has since been updated to 2023

Permitting / Siting Status
On 1/22/2021, in Decision Nos. 77888 and 77889, the Commission granted Invenergy CEC-1 and CEC-2, respectively (Case No. 187). CEC-1 is for the portion of the Project that originates at the Hashknife Solar Project to the point of future ownership change (the Point of Physical Demarcation ("POPD ") near the Cholla Substation property boundary. The companion CEC-2 is for the portion of the Project from the POPD to the point of interconnection at the Cholla Substation. At a future date, Invenergy intends to transfer CEC-2 to APS. (iv)

(iv) Information shown as originally disclosed but has since been updated to

On 1/22/2021, in Decision Nos. 77888 and 77889 (Case No. 187), the Commission granted CEC-I and CEC-2 respectively, to Hashknife Energy Center LLC. CEC-1 is for the portion of the Project that originates at the Hashknife Energy Center substation to the point of future ownership change, the Point of Physical Demarcation (POPD), near the Cholla generation plant controlled access boundary. The companion CEC-2 is for the portion of the Project from the POPD to the point of interconnection at the Cholla substation. At a future date prior to construction the Interconnection Customer intends to transfer CEC-2 to APS.

Runway 230kV Lines
Reason for addition: To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a)	Voltage Class	230kV AC
(b)	Point of Origin	Palm Valley - Rudd 230kV line
(c)	Point of Transmission	Runway Substation
(d)	Length	Less than 1 mile per circut

Date

(a)	Construction Start	2019 (i)
(b)	In Service	2022

(i) Date shown as originally disclosed but should be 2022

Permitting / Siting Status
CEC issued 11/7/2019 (Case No. 183, Decision No. 77469).

Stratus 230kV Lines
Reason for addition: To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a)	Voltage Class	230kV AC
(b)	Point of Origin	Freedom Palm Valley & Palm Valley-Rudd 230kV lines
(c)	Point of Transmission	Stratus Substation
(d)	Length	Less than 1 mile

Date

(a)	Construction Start	2021 (i)
(b)	In Service	2022

(i) Date shown as originally disclosed but has since been updated to 2022

Permitting / Siting Status
CEC issued on 12/22/2003 (Case No. 122, Decision No. 66646, West Valley South Project). Decision No. 73937 amended CEC on 6/27/2013 approving APS s application to extend the CEC term to I2/28/2018 for the first circuit of the Project and to 12/23/2028 for the second circuit and other facilities. Decision No. 77761 amended CEC on 10/2/2020 authorizing two short segments of 230kV doub1e- circuit lines and the Stratus substation. The transmission lines and Stratus substation tie into an existing 230kV transmission line authorized on 12/22/2003 in CEC 122.

Avery 230kV Lines
Reason for addition: To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a)	Voltage Class	230kV AC
(b)	Point of Origin	Scatter Wash - Raceway 230kV line
(c)	Point of Transmission	Avery 230kV Substation
(d)	Length	Less than 1 mile

Date

(a)	Construction Start	2021
(b)	In Service	2022

Permitting / Siting Status
On March 10 2021, APS filed an application to amend CEC Case No. 120 (Decision No. 65997 amended by Decision No. 73824), North Valley Project. (i)

(i) Information shown as originally disclosed but has since been updated to

"*CEC issued 6/18/2003 (CEC Case No. 120, Decision No. 65997, amended on 4/10/2013 by Decision No. 73824). On 9/29/2021, Decision No. 78251 amended the prior CEC to expand the size of Avery substation."*

Relocation of 230kV and 500kV Lines near Avery Substation
Reason for addition: To allow for the development of a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Size

(a)	Voltage Class	230kV and 500kV AC
(b)	Point of Origin	Around Avery 230kV Substation (i)
(c)	Point of Transmission	Around TS22 500/230kV Substation (ii)
(d)	Length	Approximately 3.5 miles

Date

(a)	Construction Start	2021 (iii)
(b)	In Service	2022

(i) Information shown as originally disclosed but since has been updated to "North of Avery Substation near Dove Valley Road"
(ii) Information shown as originally disclosed but since has been updated to "Approximately 1.25 miles west of 51st Avenue"
(iii) Date shown as originally disclosed but has since been updated to 2022

Permitting / Siting Status
On March 10, 2021, APS filed an application Io amend the CEC issued in Case No. 131 (Decision No. 69343). (iv)

(iv) Information shown as originally disclosed but has since been updated to
"CEC issued 2/20/2007 (Case No. 131 Decision No. 69343 Morgan-Pinnacle Peak 500k V/230k V Transmission Line Project). On 9/29/2021, Decision No. 78251 amended the CEC to relocate a segment of the Morgan-Pinnacle Peak 500kV and 230kV lines from their originally approved corridor."

During quarter three: No Additions

During quarter four: No Additions

Arizona Public Service ("APS") maintains committed revolving credit facilities in order to enhance liquidity and provide credit support for its commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

The table below presents the consolidated credit facilities and the amounts available and outstanding (dollars in thousands):

	December 31, 2021	December 31, 2020
Commitments under Credit Facilities	$ 1,000,000	$ 1,000,000
Outstanding Commercial Paper, Term Loan and Revolving Credit Facility Borrowings	(278,700)	—
Amount of Credit Facilities Available	$ 721,300	$ 1,000,000
Weighted-Average Commitment Fees	0.125%	0.100%

On May 28, 2021, APS replaced its two $500 million revolving credit facilities that would have matured in June 2022 and July 2023, respectively, with two new $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings and the agreements include a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2021, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $279 million of outstanding commercial paper borrowings.

Long-Term Debt and Liquidity Matters

All of APS's debt is unsecured. The following table presents the components of long-term debt on the Comparative Balance Sheets outstanding (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2021	December 31, 2020
Pollution control bonds:				
Variable	2029	(b)	$ 35,975	$ 35,975
Total pollution control bonds			35,975	35,975
Other long-term debt	2024-2050	2.20%-6.88%	6,310,577	5,862,534
Unamortized discount			(14,995)	(15,900)
Unamortized premium			13,575	14,781
Total long-term debt			6,345,132	5,897,390

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.
(b) The weighted-average rate for the variable rate pollution control bonds was 0.22% at December 31, 2021 and 0.18% at December 31, 2020.

The following table shows principal payments due on APS's total long-term debt (dollars in thousands):

	APS
2022	$ —
2023	—
2024	250,000
2025	300,000
2026	250,000
Thereafter	5,546,552
Total	$ 6,346,552

Credit Facilities and Debt Issuances

On August 16, 2021, APS issued $450 million of 2.2% unsecured senior notes that mature December 15, 2031. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper, replenish cash used to fund capital expenditures, and for general corporate purposes.

On December 21, 2021, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

On January 6, 2022, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

See "Lines of Credit and Short-Term Borrowings" in Note 7 and "Financial Assurances" in Note 12 for discussion of APS's separate outstanding letters of credit.

Contractual Obligations

APS has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Material contractual obligations and other commitments are as follows:

- APS has material long-term debt obligations that mature at various dates through 2050 and bear interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2021. See Note 8.
- APS maintain committed revolving credit facilities. See Note 7 for short-term debt details.
- Fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation. See Notes 5 and 12. Purchase obligations includes capital expenditures and other obligations. See Note 12. Commitments related to purchased power lease contracts are also considered fuel and purchased power commitments. See Note 10.
- APS holds certain contracts to purchase renewable energy credits in compliance with the RES. See Notes 5 and 12.
- APS must reimburse certain coal providers for amounts incurred for final and contemporaneous coal mine reclamation. See Note 12.
- APS is required to make payments to the noncontrolling interests related to the Palo Verde sale leaseback through 2033. See Note 17.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future not perform. These instruments support commodity contract collateral obligations and other transactions. As of December 31, 2021, standby letters of credit totaled approximately $0.2 million and will expire in 2022. As of December 31, 2021, surety bonds expiring through 2023 totaled approximately $14 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Authorizations

On December 17, 2020, the Arizona Corporation Commission ("ACC") issued a financing order, Decision No. 77853, in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power).

The financing order also approved, subject to specified parameters and procedures, an increase in APS's long-term debt authorization from $5.9 billion to $7.5 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs.
APS's issuances of short-term debt are authorized by the ACC in its Decision No. 77853 and/or by Arizona Revised Statutes Section 40-302.D and the issuances of long-term debt are authorized by the ACC in its Decision No. 77853.

7 None.

8

The union and non-union annualized wage scale increases for active employees during 2021 as of December 31, 2021, were as follows:

	Type of Cost	Number of Increases	Annualized Costs
a.	Union Negotiated	1,143	$ 2,738,456
b.	Non-Union Base Salary Increases	3,844	12,270,935
c.	Special Increases	414	1,539,634
d.	Promotions	781	6,818,782
	Total	**6,182**	**$ 23,367,807**

COMMENTS:
a. There were general wage increases for the International Brotherhood of Electrical Workers ("IBEW"), (averaging 2.5%) during second quarter.
b. The overall non-union employee merit budget was 3.0%. Actual merit adjustments ranged from 0% to 8.0% based upon an employee's performance and their pay position within the salary range. Merit pay awards were added to base pay.
c. Salary adjustments to base pay are awarded to non-union employees throughout the year in special instances.
d. Promotions were awarded to union and non-union employees due to changes in job functions or grade level changes.

9

Legal Proceedings

I. LITIGATION & ENVIRONMENTAL MATTERS

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high-level waste from January 1, 2007, through June 30, 2011, pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, which required DOE to pay the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007, through June 30, 2011. The settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019. On
September 1, 2020, APS and DOE entered into an addendum to the settlement agreement allowing for the recovery of costs incurred through December 31, 2022.

APS has submitted seven claims pursuant to the terms of the August 18, 2014, settlement agreement, for seven separate time periods during July 1, 2011, through June 30, 2020. DOE has approved and paid $111.8 million for these claims (APS's share is $32.5 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers (see "Cholla" below). On November 1, 2021, APS filed its eighth claim pursuant to the terms of the August 18, 2014, settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). In February 2022, the DOE approved this claim.

Superfund-Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible ("PRPs"). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that the Environmental Protection Agency ("EPA") considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS during the first or second quarter of 2022. APS's estimated costs related to this investigation and study is approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2021. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See "Four Corners SCR Cost Recovery" below for additional information.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases ("GHGs"), water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on Four Corners Power Plant ("Four Corners"). EPA required the plant to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plant.

Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. In addition, APS and El Paso Electric Company ("El Paso") entered into an asset purchase agreement providing for the purchase by APS,
or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4C Acquisition, a wholly owned subsidiary of Pinnacle West ("4CA") purchased the El Paso interest on July 6, 2016. Navajo Transitional Energy Company, LLC ("NTEC") purchased the interest from 4CA on July 3, 2018. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest. In addition, EPA issued a final rule for Regional Haze compliance at Cholla Power Plant ("Cholla") that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See "Cholla" below for information regarding future plans for Cholla and details related to the resulting regulatory asset.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019, to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- Based on an August 21, 2018, D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On July 29, 2020, EPA took final action on new regulations establishing revised deadlines for initiating the closure of unlined CCR surface impoundments by April 11, 2021, at the latest. All APS disposal units subject to these closure requirements were closed as of April 11, 2021.

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's July 29, 2020, final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure (which would allow the continued disposal of CCR within the facility's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025) was submitted to EPA on November 30, 2020, and is currently pending. This application will be subject to public comment and, potentially, judicial review. On January 11, 2022, EPA began issuing proposed decisions pursuant to this provision of the federal CCR regulations and we anticipate receiving a proposed decision with respect to the Cholla facility in 2022.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Generating Station ("Navajo Plant") disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan/Affordable Clean Energy Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE
regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. Nonetheless, on October 29, 2021, the U.S. Supreme Court announced that it was accepting judicial review of the January D.C. Circuit decision vacating the ACE regulations. While the Biden administration has expressed an intent to regulate carbon emissions in this sector more aggressively under the Clean Air Act, we cannot at this time predict the outcome of pending EPA rulemaking proceedings or ongoing litigation related to the scope of EPA's authority under the Clean Air Act to regulate carbon emissions from existing power plants.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. EPA then issued a revised final NPDES permit for Four Corners on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the EAB again took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and the EAB denied the environmental group petition on September 30, 2020. On January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. The September 2019 permit remains in effect pending this appeal. As of November 11, 2021, the parties to this lawsuit, including APS, reached a tentative agreement to settle this matter. Review of this agreement, including public commenting, is currently pending with EPA. Notwithstanding this tentative agreement, we cannot predict the outcome of these appeal proceedings, including further settlement discussions, and, if settlement efforts fail and the appeal is eventually successful, whether that outcome will have a material impact on our financial position, results of operations, or cash flows.

II. REGULATORY MATTERS

COVID-19 Pandemic

During 2020 and 2021, APS implemented several programs and initiatives to help our customers deal with the economic and other impacts of the COVID-19 pandemic, including but not limited to the following:

- *Suspension of Disconnections; Waiver of Late Payment Fees*. APS voluntarily suspended disconnections of customers for nonpayment beginning March 13, 2020, until December 31,
2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and customers with past due balances of $75 or greater as of that date were automatically placed on eight-month payment arrangements. APS voluntarily began waiving late payment fees of its customers on March 13, 2020, and is continuing to waive late payment fees. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium (defined below) and the related write-offs of customer delinquent accounts.

- *COVID-19 Emergency Relief Package*. On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the Demand Side Management ("DSM") Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the Kilowatt hour ("kWh") credit being based on historic consumption, which was different than actual consumption during the refund period.

- *COVID Customer Support Fund*. In 2020, APS spent more than $15 million to assist customers and local non-profits and community organizations to help with the impact of the COVID-19 pandemic, with $12.4 million of these dollars directly committed to bill assistance programs (the "COVID

COVID Customer Support Fund. In 2020, APS spent more than $15 million to assist customers and local non-profits and community organizations to help with the impact of the COVID-19 pandemic, with $12.4 million of these dollars directly committed to bill assistance programs (the "COVID Customer Support Fund"). The COVID Customer Support Fund was comprised of (i) approximately $8.8 million in funds that are not recoverable through rates, and (ii) an additional $3.6 million in bill credits for limited income customers ordered by the ACC in December 2020, of which 50%, up to a maximum of $2.5 million, was committed to be funds that are not recoverable through rates, with the remaining bill credits being deferred for potential future recovery in rates. Included in the COVID Customer Support Fund were programs that assisted customers with a delinquency of two or more months, providing a one-time credit of $100, an expanded credit of $300 for limited income customers, programs to assist extra small and small non-residential customers with a one-time credit of $1,000, and other targeted programs allocated to assist with other COVID-19 needs in support of utility bill assistance. The December 2020 ACC order further assisted delinquent limited income customers with an additional bill credit of up to $250 or their delinquent balance, whichever was less. APS has distributed all funds for all COVID Customer Support Fund programs combined. Beyond the COVID Customer Support Fund, APS has also provided $2.7 million to assist local non-profits and community organizations working to mitigate the impacts of the COVID-19 pandemic.

- *Deferral of Power Supply Adjustor ("PSA") Rate Increase.* In February 2021, APS delayed the annual reset of the PSA, with 50% of the PSA rate increase taking effect in April 2021 and the remaining 50% taking effect in November 2021. See below for discussion of the PSA.

2019 Retail Rate Case

APS filed an application with the ACC on October 31, 2019 (the "2019 Rate Case") seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project that was the subject of a separate proceeding. See "Four Corners SCR Cost Recovery" below. It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the Tax Expense Adjustment Mechanism ("TEAM"). The proposed total annual revenue
increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	45.3 %	4.10 %
Common stock equity	54.7 %	10.15 %
Weighted-average cost of capital		7.41 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.030168 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- authorization to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- a number of proposed rate and program changes for residential customers, including:
  - a super off-peak period during the winter months for APS's time-of-use with demand rates;
  - additional $1.25 million in funding for APS's limited-income crisis bill program; and
  - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;
- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Plant (see "Navajo Plant" below).

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommended, among other things, (i) a $89.7 million revenue increase, (ii) an average annual customer bill increase of 2.7%, (iii) a return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) the recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) the recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommended, among other things, (i) a $20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, a (i) $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism, to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition ("CCT") plan related to the closure or future closure of coal-fired generation facilities, of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020, financials. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, and this amount was recognized in our December 31, 2021, financials.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%. The hearing concluded on March 3, 2021, and the post-hearing briefing concluded on April 30, 2021.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following
components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the RES adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20-basis-point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m., but did not explicitly approve the 10 months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by April 1, 2022. On January 12, 2022, the ACC voted to extend the deadline until September 1, 2022, to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

APS expects to file an application with the ACC for its next general retail rate case by mid-year 2022 but is continuing to evaluate the timing of such filing.

Information Technology ACC Investigation

On December 16, 2021, the ACC opened an investigation into various matters related to APS's Information Technology department, including information about technology projects, costs, vendor management leadership and decision making. APS is cooperating with the investigation. The ACC Staff has been directed to report to the ACC on the investigation in April 2022. APS cannot predict the outcome of this matter.

2016 Retail Rate Case Filing

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, the RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules.

Other key provisions of the 2017 Settlement Agreement include the following:

- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing SCR equipment at Four Corners;
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the PSA to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as APS Solar Communities) for utility-owned solar distributed generation ("DG") with the purpose of expanding access to rooftop solar for low- and moderate-income Arizonans, recoverable through the RES, to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
  - a change in the on-peak time-of-use period from noon to 7 p.m. to 3 p.m. to 8 p.m. Monday through Friday, excluding holidays;
  - non-grandfathered DG customers would be required to select a rate option that has time-of-use rates and either a new grid access charge or demand component;
  - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027, for combined-cycle generating units), unless expressly authorized by the ACC.

On August 15, 2017, the ACC approved the 2017 Settlement Agreement without material modifications and on August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"). The new rates went into effect on August 19, 2017.

See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms.

Renewable Energy Standard ("RES"). In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas, and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget. In 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2020. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2020. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 Demand Side Management Implementation Plan ("DSM Plan").

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its integrated resource plan ("IRP"), and seek cost recovery in a rate process. Since the adopted
clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source requests for proposals ("RFP") requirements and the IRP process. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget includes funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the 2019 Rate Case decision. APS's budget proposal supports existing approved projects and commitments and requests a permanent waiver of the RES residential and non-residential distributed energy requirements for 2022. The ACC has not yet ruled on the 2022 RES Implementation Plan.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards ("EES") requires APS to submit a DSM Plan annually for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its Lost Fixed Cost Recovery ("LFCR") mechanism. See below for discussion of the LFCR.

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the DSM portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan sought a requested budget of $52.6 million and requested a waiver of the Electric Energy Efficiency Standard for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels but kept the overall budget at $52.6 million.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the
kWh credit being based on historic consumption which was different than actual consumption during the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, as described below.

On December 31, 2020, APS filed its 2021 DSM Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Plan that proposed an additional performance incentive for customers participating in the residential energy storage pilot program approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Plan.

On April 20, 2021, APS filed a request to extend the June 1, 2021, deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved the request, granting an extension until 120 days after the ACC action on the 2021 DSM Plan, or

December 31, 2021, whichever is later. On December 17, 2021, APS filed its 2022 DSM Plan which requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;
- an adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- the PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- the PSA rate includes (a) a "forward component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "historical component," under which differences between actual fuel and purchased power costs and those recovered or refunded through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "transition component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and
- the PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2021 and 2020 (dollars in thousands):

	Twelve Months Ended December 31,	
	2021	2020
Beginning balance	$ 175,835	$ 70,137
Deferred fuel and purchased power costs - current period	256,871	93,651
Amounts refunded/(charged) to customers	(44,558)	12,047
Ending balance	$ 388,148	$ 175,835

The PSA rate for the PSA year beginning February 1, 2019, was $0.001658 per kWh, as compared to the $0.004555 per kWh for the prior year. This rate was comprised of a forward component of $0.000536 per kWh and a historical component of $0.001122 per kWh. This represented a $0.002897 per kWh decrease compared to 2018. These rates went into effect as filed on February 1, 2019.

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh, which consisted of a forward component of $(0.002086) per kWh and a historical component of $0.001630 per kWh. The 2020 PSA rate is a $0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh, which consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the PSA rate increase taking effect in April 2021 and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021, was $0.001544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a PSA rate of $0.003544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit, which is currently underway, to better understand the factors that contributed to the increase in fuel costs. APS cannot predict the outcome of this audit.

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate is a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022. At the time of the compliance filing, the amount remaining over the annual cap was approximately $365 million of fuel and purchased power costs which will be reflected in future year resets of the PSA.

On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA. On December 29, 2020, the ACC Staff filed its report and recommended the storage costs be included in the PSA once the systems are in-service. On January 12, 2021, the ACC approved this application but did not rule on the prudency. On October 28, 2021, APS filed an application requesting approval to recover costs related to three additional energy storage projects through the PSA once the systems are in service. On December 16, 2021, the ACC approved this application but did not rule on the prudency. APS cannot predict the outcome of this matter.

Environmental Improvement Surcharge ("EIS"). The EIS permits APS to recover the capital carrying costs (rate of return, depreciation, and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1
each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2022, application requested an increase in the charge to $11.4 million, or $1.1 million over the prior-period charge, and it will become effective with the first billing cycle in April 2022 absent the ACC taking action.

Transmission Rates, Transmission Cost Adjustor ("TCA") and Other Transmission Matters. In July 2008, the Federal Energy Regulatory Commission ("FERC") approved a modification to APS's Open Access Transmission Tariff to allow APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the settlement agreement entered into in 2012 regarding APS's rate case ("2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. APS reviews the proposed formula rate filing amounts with the ACC Staff. Any items or adjustments which are not agreed to by APS and the ACC Staff can remain in dispute until settled or litigated with FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 17, 2020, APS made a filing to make modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Cuts and Jobs Act ("Tax Act"), as well as for future local, state, and federal statutory tax rate changes. APS amended its March 17, 2020, filing on April 28, 2020, September 29, 2021, and October 27, 2021. In January 2022, FERC approved APS's modifications to its annual transmission formula.

Effective June 1, 2019, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $25.8 million for the 12-month period beginning June 1, 2019, in accordance with the FERC-approved formula. Of this amount, wholesale customer rates increased by $21.1 million and retail customer rates would have increased by approximately $4.7 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved TCA balancing account, the retail revenue requirement increased by a total of $4.9 million, resulting in a decrease to residential rates and an increase to commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2019.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the 12-month period beginning June 1, 2020, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million.
However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential and 2.68 cents non-residential kWh as set forth in the 2019 Rate Case decision. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). On July 10, 2019, the ACC approved APS's 2019 LFCR adjustment as filed, effective with the next billing cycle of July 2019. On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment, thus the previously approved rates continue to remain intact. The $11.8 million will continue to be maintained in the LFCR regulatory asset balancing account and will be included in APS's next LFCR

19, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment, thus the previously approved rates continue to remain intact. The $11.8 million will continue to be maintained in the LFCR regulatory asset balancing account and will be included in APS's next LFCR application filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism as a result of the 2019 Rate Case decision did not materially impact its results of operations and financial statements for the year ended December 31, 2021.

On February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels). The ACC's final determination of APS's 2022 annual LFCR adjustment filing and related earnings test may materially impact the timing and amounts of future LFCR revenue recognition. See Note 2 for a discussion of alternative revenue program accounting treatment related to certain regulatory cost recovery mechanisms and see the Regulatory Assets and Liabilities table below. APS cannot predict the outcome or timing of the ACC's consideration and final determination of its 2022 annual LFCR adjustment filing.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On August 13, 2018, APS filed a request with the ACC that addressed the return of $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 will be recorded as a part of the balancing account and will be addressed for recovery as part of the 2019 Rate Case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit are recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which will provide an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of the 2019 Rate Case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit are recognized based upon APS's seasonal kWh sales pattern.

As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021, and all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS's next rate case.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a RCP methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted
avoided cost methodology is being developed. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to September 1, 2017, based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies.

In accordance with the 2017 Rate Case Decision, APS filed its request for an export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021.

See "2016 Retail Rate Case Filing" above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

After various proceedings between September 2016 and March 2020, at which time Burns' appeal of a prior dismissal by the trial court was pending before the Arizona Court of Appeals, Burns' position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. On March 4, 2021, the Court of Appeals found Burns' motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day.

In its March 4, 2021, opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021, requesting that the petition be denied. The Arizona Supreme Court granted Burns' petition and oral argument is scheduled for March 8, 2022. Pinnacle West and APS cannot predict the outcome of this matter.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the IRP process. On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and subsequent drafts were filed by ACC Staff in July 2019, February 2020, and July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. A new EES was not included in the proposed rules. These rules would have required utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, these rules would have changed the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the
deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS's IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by 2030 and authorizing future rate base treatment of qualifying demand-side resources as proposed in future rate cases. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 (“PURPA”), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. “Avoided cost” is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year Power Purchase Agreements ("PPAs") with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

On July 16, 2020, FERC issued a final rule revising FERC’s regulations implementing PURPA. The final rule went into effect on December 31, 2020.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 (“Summer Disconnection Moratorium”). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur and customers will have four months to pay back their deposit and any remaining delinquent amounts. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method (June 1 – October 15) for disconnection moratoriums. On November 2, 2021, the ACC approved the final rules, and on November 23, 2021, the rules were submitted to the Arizona Office of the Attorney General for final review and approval. Although the rules are not yet final, APS intends to employ the calendar method for its disconnection moratorium. This is consistent with APS’s existing disconnection moratorium processes since 2019.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC’s retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC’s retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. At the same time, the Arizona legislature is considering a bill that would nullify, if approved, a 20-year-old electric deregulation law that has been in place since 1998. The bill has several procedural steps in the legislative process before becoming law. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS’s and Tucson Electric Power Company’s certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy’s application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC’s ability to issue competitive certificates convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS’s meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS’s financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant’s report on APS’s rate comparison tool. The report concluded APS’s new rate comparison tool is working as intended.
The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS’s financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section (“Attorney General”) seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General’s Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which has been returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff”s recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. The ACC did not issue a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Rate Case filing with the ACC.

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2021. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See above for further discussion on the 2019 Rate Case decision.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of Cholla and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS’s plan to retire Unit 2, without expressing any view on the future recoverability of APS’s remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS’s compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS has committed to end the use of coal at its remaining Cholla units by 2025.

Previously, APS estimated Cholla Unit 2’s end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit’s decommissioning and other retirement-related costs ($41.8 million as of December 31, 2021), in addition to a return on its investment. In accordance with accounting principles generally accepted in the United States of America ("GAAP"), in the third quarter of 2014, Unit 2’s remaining net book value was reclassified from property, plant and equipment to a regulatory asset. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allows for decommissioning activities to begin after the plant ceased operations. In accordance with GAAP, in the second quarter of 2017, APS’s remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset.

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant ($62.2 million as of December 31, 2021), in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset ($16.8 million as of December 31, 2021). The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

10 None.

12 N/A

13

Board and Officer Elections, Retirements, Resignations and Changes During 2021:

Directors – Note – all of the Directors are voted on or reappointed in May.

- Humberto S. Lopez retired from the Board of Directors of APS and Pinnacle West Capital Corporation on May 19, 2021.

Officers – Note – all of the Officers are re-elected in May.

- On February 8, 2021, Monica Whiting's title was changed to Vice President Customer Experience and Communications.
- On April 1, 2021, Daniel T. Froetscher, President and Chief Operating Officer of APS announced his retirement, effective August 31, 2021.
- On April 21, 2021, Patrick Dinkel, Vice President Strategy and Risk of APS, announced his retirement, effective August 31, 2021.
- On May 19, 2021, Jeffrey B. Guldner was appointed President of APS, effective August 13, 2021. He kept all other titles.
- On May 19, 2021, Daniel T. Froetscher was appointed President and Chief Operating Officer of APS until August 13, 2021.
- On May 19, 2021, Bradley J. Albert was appointed Vice President, Resource Management of APS through May 31, 2021.
- On May 19, 2021, Jacob Tetlow was appointed Executive Vice President, Operations of APS.
- On May 19, 2021, Justin M. Joiner was appointed Vice President, Resource Management of APS, effective upon the start of his employment with APS, which was June 7, 2021.
- On June 23, 2021, Robert E. Smith was appointed Executive Vice President, General Counsel and Chief Development Officer of APS and Pinnacle West.
- On August 24, 2021, Jim Hatfield, EVP & Chief Administrative Officer, announced his retirement, effective December 31, 2021.
- On August 30, 2021, Jim Hatfield's title was changed to Advisor to the CEO.
- On October 20, 2021, Michelle Ferrara was appointed VP, Chief Information Officer to be effective October 6, 2021.
- On October 20, 2021, John Lucas was appointed as VP Generation (non-nuclear).
- On December 15, 2021, Cary D. Harbor was appointed VP Regulatory & Oversight – Palo Verde Generating Station effective February 7, 2022.

14 N/A

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	23,785,603,245	22,492,195,788
3	Construction Work in Progress (107)	200	1,210,177,757	814,449,488
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		24,995,781,002	23,306,645,276
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	8,331,220,117	7,935,132,087
6	Net Utility Plant (Enter Total of line 4 less 5)		16,664,560,885	15,371,513,189
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	119,818,855	124,637,619
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		(1,683)	
9	Nuclear Fuel Assemblies in Reactor (120.3)		239,162,171	250,852,003
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	133,121,924	137,206,939
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		225,857,419	238,282,683
14	Net Utility Plant (Enter Total of lines 6 and 13)		16,890,418,304	15,609,795,872
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		7,486,575	10,114,263
19	(Less) Accum. Prov. for Depr. and Amort. (122)		90,418	3,639,669
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		2,190,864,957	1,892,048,702
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		48,302,351	3,149,731
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,246,563,465	1,901,673,027
33	**CURRENT AND ACCRUED ASSETS**			

34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		5,433,352	55,265,017
36	Special Deposits (132-134)			
37	Working Fund (135)		3,866,020	1,746,020
38	Temporary Cash Investments (136)		75,019	299,267
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		292,414,204	254,073,667
41	Other Accounts Receivable (143)		98,097,118	58,546,984
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		25,354,026	19,781,744
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		22,111	22,673
45	Fuel Stock (151)	227	10,380,456	13,378,320
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	349,405,026	316,139,165
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	7,651,066	6,173,305
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	(270,325)	(1,394,570)
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		66,246,118	45,330,671
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		133,980,067	132,196,822
62	Miscellaneous Current and Accrued Assets (174)		36,162,724	36,208,391
63	Derivative Instrument Assets (175)		115,079,746	9,020,263
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		48,302,351	3,149,731
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		1,044,886,325	904,074,520
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		47,861,489	46,911,224
70	Extraordinary Property Losses (182.1)	230a		

71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	1,690,573,528	1,404,829,825
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,337,037	818,001
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		532,444	858,791
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	29,659,130	30,479,111
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		11,019,871	12,565,165
82	Accumulated Deferred Income Taxes (190)	234	1,081,616,724	952,240,255
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		2,864,600,223	2,448,702,372
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		23,046,468,317	20,864,245,791

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	178,162,368	178,162,368
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		3,040,807,686	2,890,807,686
7	Other Paid-In Capital (208-211)	253	18,400,365	18,400,365
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	37,511,652	37,511,652
11	Retained Earnings (215, 215.1, 216)	118	3,470,235,012	3,216,954,483
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(34,880,386)	(40,918,350)
16	Total Proprietary Capital (lines 2 through 15)		6,635,213,393	6,225,894,900
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	35,975,000	35,975,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	6,310,576,738	5,862,533,545
22	Unamortized Premium on Long-Term Debt (225)		13,574,557	14,780,963
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		14,994,744	15,899,441
24	Total Long-Term Debt (lines 18 through 23)		6,345,131,551	5,897,390,067
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		913,109,063	518,167,336
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		741,979	745,000
29	Accumulated Provision for Pensions and Benefits (228.3)		189,520,109	199,574,137
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		1,394,062	12,393,671

33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		767,382,593	705,082,847
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,872,147,806	1,435,962,991
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		278,700,000	
38	Accounts Payable (232)		389,260,216	311,662,091
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		103,541,789	111,419,556
41	Customer Deposits (235)		42,292,969	48,339,747
42	Taxes Accrued (236)	262	178,311,609	174,684,387
43	Interest Accrued (237)		57,942,476	58,177,415
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		104,728	37,059
48	Miscellaneous Current and Accrued Liabilities (242)		139,378,781	172,995,193
49	Obligations Under Capital Leases-Current (243)		113,392,488	89,804,495
50	Derivative Instrument Liabilities (244)		7,478,043	21,605,396
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		1,394,062	12,393,671
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,309,009,037	976,331,668
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		257,151,039	221,031,992
57	Accumulated Deferred Investment Tax Credits (255)	266	186,569,907	191,371,520
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	304,515,263	247,010,705
60	Other Regulatory Liabilities (254)	278	2,713,540,369	2,561,386,227
61	Unamortized Gain on Reaquired Debt (257)		68,563	111,866
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		2,566,397,208	2,477,515,467
64	Accum. Deferred Income Taxes-Other (283)		856,724,181	630,238,388
65	Total Deferred Credits (lines 56 through 64)		6,884,966,530	6,328,666,165
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		23,046,468,317	20,864,245,791

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	3,823,902,542	3,591,983,986			3,823,902,542	3,591,983,986				
3	Operating Expenses											
4	Operation Expenses (401)	320	1,788,728,884	1,674,129,148			1,788,728,884	1,674,129,148				
5	Maintenance Expenses (402)	320	208,904,615	199,038,948			208,904,615	199,038,948				
6	Depreciation Expense (403)	336	536,310,780	512,914,827			536,310,780	512,914,827				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	5,881,163	4,748,081			5,881,163	4,748,081				
8	Amort. & Depl. of Utility Plant (404-405)	336	102,629,990	95,573,570			102,629,990	95,573,570				
9	Amort. of Utility Plant Acq. Adj. (406)	336	10,873,443	10,873,443			10,873,443	10,873,443				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		31,427,316	31,100,867			31,427,316	31,100,867				
13	(Less) Regulatory Credits (407.4)		40,088,564	44,167,318			40,088,564	44,167,318				
14	Taxes Other Than Income Taxes (408.1)	262	261,628,912	251,065,425			261,628,912	251,065,425				
15	Income Taxes - Federal (409.1)	262	(3,014,454)	56,608,992			(3,014,454)	56,608,992				

16	Income Taxes - Other (409.1)	262	(1,555,134)	(255,051)			(1,555,134)	(255,051)				
17	Provision for Deferred Income Taxes (410.1)	234, 272	598,584,448	670,798,645			598,584,448	670,798,645				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	465,074,398	629,249,378			465,074,398	629,249,378				
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		28,498	30,184			28,498	30,184				
23	Losses from Disposition of Allowances (411.9)		29,761	33,051			29,761	33,051				
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,035,238,264	2,833,183,066			3,035,238,264	2,833,183,066				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		788,664,278	758,800,920			788,664,278	758,800,920				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		2,574,515	1,417,172								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,210,146	1,041,988								
33	Revenues From Nonutility Operations (417)											
34	(Less) Expenses of Nonutility Operations (417.1)		67,020	828,981								
35	Nonoperating Rental Income (418)		40,376	9,576								
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		4,691,743	9,620,805								
38	Allowance for Other Funds Used During Construction (419.1)		41,736,820	33,776,170								
39	Miscellaneous Nonoperating Income (421)		297,432,535	449,888,464								
40	Gain on Disposition of Property (421.1)		3,952,844	3,438,285								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		348,151,667	496,279,503								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		4,182,434	6,245,777								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		8,505,760	53,953,677								
46	Life Insurance (426.2)											
47	Penalties (426.3)		311,198	5,112								

48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,722,200	2,812,643									
49	Other Deductions (426.5)		269,124,818	417,732,613									
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		284,846,410	480,749,822									
51	Taxes Applic. to Other Income and Deductions												
52	Taxes Other Than Income Taxes (408.2)	262	536,398	519,370									
53	Income Taxes-Federal (409.2)	262	6,217,081	1,105,319									
54	Income Taxes-Other (409.2)	262	1,543,644	353,917									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	93,276	930,631									
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,193,241	3,421,637									
57	Investment Tax Credit Adj.-Net (411.5)												
58	(Less) Investment Tax Credits (420)		8,513,538	8,373,712									
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(2,316,380)	(8,886,112)									
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		65,621,637	24,415,793									
61	Interest Charges												
62	Interest on Long-Term Debt (427)		231,351,615	216,351,980									
63	Amort. of Debt Disc. and Expense (428)		4,139,583	3,803,824									
64	Amortization of Loss on Reaquired Debt (428.1)		1,594,940	1,592,117									
65	(Less) Amort. of Premium on Debt-Credit (429)		1,206,406	461,706									
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		43,303	43,303									
67	Interest on Debt to Assoc. Companies (430)												
68	Other Interest Expense (431)		7,220,489	12,475,099									
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		21,051,532	18,529,516									
70	Net Interest Charges (Total of lines 62 thru 69)		222,005,386	215,188,495									
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		632,280,529	568,028,218									
72	Extraordinary Items												
73	Extraordinary Income (434)												
74	(Less) Extraordinary Deductions (435)												
75	Net Extraordinary Items (Total of line 73 less line 74)												
76	Income Taxes-Federal and Other (409.3)	262											
77	Extraordinary Items After Taxes (line 75 less line 76)												

78	Net Income (Total of line 71 and 77)		632,280,529	568,028,218									

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		3,216,954,483	3,011,926,265
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		632,280,529	568,028,218
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1		234	379,000,000	363,000,000
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		379,000,000	363,000,000
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,470,235,012	3,216,954,483
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,470,235,012	3,216,954,483
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			

50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	632,280,529	568,028,218
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	542,191,943	517,661,253
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of UTL PLT; ACQ; ADJ; Prop Loss; Reg Study; Nuclear Fuel	172,816,743	165,255,203
5.2	Deferred Fuel and Purchased Power	(212,314,848)	(105,697,843)
8	Deferred Income Taxes (Net)	127,698,159	35,780,533
9	Investment Tax Credit Adjustment (Net)	(4,801,612)	(5,095,984)
10	Net (Increase) Decrease in Receivables	(73,885,422)	(32,236,851)
11	Net (Increase) Decrease in Inventory	(31,392,243)	13,435,721
12	Net (Increase) Decrease in Allowances Inventory	(1,477,761)	(1,811,766)
13	Net Increase (Decrease) in Payables and Accrued Expenses	13,132,219	2,659,844
14	Net (Increase) Decrease in Other Regulatory Assets	(34,008,358)	(25,600,068)
15	Net Increase (Decrease) in Other Regulatory Liabilities	117,132,713	77,159,990
16	(Less) Allowance for Other Funds Used During Construction	41,736,820	33,776,170
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other Current Assets	(223,362)	28,188
18.2	Income Tax Receivable	(10,755,546)	7,313,230
18.3	Prepaids	(10,159,901)	(8,634,927)
18.4	Risk Management	247,448	(91,200)
18.5	Other Current Liabilities	(992,640)	(247,922)
18.6	Accrued Taxes	4,195,485	13,324,251
18.7	Arizona Attorney General Settlement	(24,526,978)	24,750,000
18.8	Carbon Allowance Other Current Liabilities	(3,669,453)	4,842,420
18.9	Community Coal Transition - ST	2,060,000	790,000
18.10	Customer Deposits	(6,046,779)	(16,567,884)

18.11	Employee Benefits	(1,116,236)	6,801,377
18.12	Exchange	(6,219,331)	(86,000)
18.13	Fossil Tail Costs		(2,323,329)
18.14	Four Corners Take or Pay	(4,334,915)	(2,145,786)
18.15	Interest Accrued	(234,938)	3,969,794
18.16	Payroll Accrual	192,191	4,287,778
18.17	SCE Right of Way	862,827	(9,950,473)
18.18	Software License Agreements	1,769,469	(1,225,833)
18.19	SunEdison Line of Credit		(2,000,000)
18.20	Unbilled Revenue	62,655	54,564
18.21	Uncertain Tax Position Current Liabilities	(568,263)	2,219,609
18.22	Operating Leases	56,987	5,244,199
18.23	Other Long Term Assets/Liabilities Net		
18.24	Active Union Medical Trust	3,485,049	(7,531,922)
18.25	Asset retirement obligations expenditures	(4,451,000)	(9,710,000)
18.26	Carbon Allowance	5,260,563	(3,118,592)
18.27	Community Coal Transition	(1,160,000)	24,410,000
18.28	Coal Reclamation	4,518,846	4,401,904
18.29	Coal Reclamation Escrow	87,619	(1,073,523)
18.30	Customer advances for construction	36,119,047	5,701,890
18.31	Decommissioning Trust	(154,040,459)	(125,379,304)
18.32	Information Systems Maintenance	2,020,335	(3,333,964)
18.33	Interconnection Deposits	13,879,889	
18.34	Interconnection Study	24,525,169	7,095,963
18.35	Long Term Operating Leases	(108,215,276)	(75,161,724)
18.36	Operating Lease - Right of Use Assets	115,849,780	82,174,064
18.37	Pension and other benefits	(1,834,000)	(136,212,000)
18.38	Postretirement assets	(178,637,076)	(2,233,281)
18.39	Retention Accrual	12,915,709	
18.40	Software License Agreement	(1,610,090)	(2,409,663)
18.41	Utility Plant (Removal Costs)	(69,206,482)	(57,603,879)
18.42	Other Long-Term Assets/Liabilities Net	(476,136)	2,031,964
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	845,265,449	908,162,069
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,471,075,055)	(1,234,171,405)
27	Gross Additions to Nuclear Fuel	(55,840,952)	(66,455,308)

28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	21,051,532	18,529,516
31	Other (provide details in footnote):		
31.1	Contributions in Aid of Construction	105,869,000	79,852,000
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,442,098,539)	(1,239,304,229)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables	(215,650)	(17,348,114)
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	54,155,808	(27,795,591)
53	Other (provide details in footnote):		
53.1	Proceeds from Trust and Other Special Use Funds Sales (a)	1,720,965,728	819,518,461
53.2	Investment in Trust and Other Special Use Funds (a)	(1,725,480,386)	(822,608,020)
53.3	Other (provide details in footnote):		
53.4	Investments and Other Assets		
53.5	Post-Employment Benefits	(151,781)	549,085
53.6	Restricted Cash Investments	2,826,249	(1,038,819)
53.7	Other Assets	(2,401,291)	(65,404)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,392,399,862)	(1,288,092,631)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	446,998,500	1,099,721,683
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Equity Infusion from Pinnacle West	150,000,000	150,000,000
66	Net Increase in Short-Term Debt (c)	278,700,000	

67	Other (provide details in footnote):		
67.1	Short-term debt borrowings under revolving credit facility		540,000,000
67.2	Short-term debt repayments under revolving credit facility		(540,000,000)
70	Cash Provided by Outside Sources (Total 61 thru 69)	875,698,500	1,249,721,683
72	Payments for Retirement of:		
73	Long-term Debt (b)		(465,150,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(376,500,000)	(357,500,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	499,198,500	427,071,683
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(47,935,913)	47,141,121
88	Cash and Cash Equivalents at Beginning of Period	57,310,304	10,169,183
90	Cash and Cash Equivalents at End of Period	9,374,391	57,310,304

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

1. Other Comprehensive Basis of Accounting

The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). The primary differences in the accompanying FERC financial statements as compared to GAAP include presenting certain decommissioning and reclamation activities, deferred tax assets and liabilities, regulatory assets and liabilities and risk management assets and liabilities on a gross versus net basis; presenting cost of removal liabilities in accumulated provision for depreciation; presenting tax liabilities related to uncertain tax positions as deferred income tax liabilities; presenting intangible assets in net utility plant; deconsolidating certain Variable Interest Entities ("VIE") and presenting debt issuance costs in deferred debits rather than as a reduction of long-term debt. Additionally, the accompanying FERC financial statements do not separately present the current portion of such items as long-term debt, Asset Retirement Obligations ("ARO") and regulatory assets and liabilities as required by GAAP.

Arizona Public Service's ("APS") notes to financial statements have been combined with Pinnacle West Capital Corporation's financial statements and are prepared in accordance with GAAP; accordingly, certain footnotes are not reflective of APS's financial statements contained herein.

2. Summary of Significant Accounting Policies

Nature of Operations

APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the Arizona Corporation Commission ("ACC") and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred and are refundable to customers.

Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. Management judgments also include assessing the impact of potential Commission-ordered refunds to customers on regulatory liabilities. See Note 5 for additional information.

Electric Revenues

Revenues primarily consist of activities that are classified as revenues from contracts with customers. Our electric revenues generally represent a single performance obligation delivered over time. We have elected to apply the practical expedient that allows us to recognize revenue based on the amount to which we have a right to invoice for services performed.

We derive electric revenues primarily from sales of electricity to our regulated retail customers.
Revenues related to the sale of electricity are generally recognized when service is rendered or electricity is delivered to customers. Unbilled revenues are estimated by applying an average revenue/kWh by customer class to the number of estimated kWhs delivered but not billed. Differences historically between the actual and estimated unbilled revenues are immaterial. We exclude sales taxes and franchise fees on electric revenues from both revenue and taxes other than income taxes.

Revenues from our regulated retail customers and non-derivative instruments are reported on a gross basis on APS's Comparative Statements of Income. In the electricity business, some contracts to purchase electricity are netted against other contracts to sell electricity. This is called a "book- out" and usually occurs for contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow. We report these book-outs on a gross basis presenting both revenues and fuel and purchased power costs.

Some of our cost recovery mechanisms are alternative revenue programs. For alternative revenue programs that meet specified accounting criteria, we recognize revenues when the specific events permitting billing of the additional revenues have been completed. See Notes 3 and 5 for additional information.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. See Note 3.

Property, Plant and Equipment

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;

- capitalized leases;
- construction overhead costs (where applicable); and
- Allowance for Funds Used During Construction ("AFUDC").

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense, and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 13 for additional information.

APS records a regulatory liability for the excess that has been recovered in regulated rates over the amount calculated in accordance with guidance on accounting for AROs. APS believes it is probable it will recover in regulated rates, the costs calculated in accordance with this accounting guidance.

We record depreciation and amortization on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2021, were as follows:

- Steam generation — 12 years;
- Nuclear plant — 25 years;
- Other generation — 19 years;
- Transmission — 37 years;
- Distribution — 33 years; and
- General plant — 7 years.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. For the years 2020 through 2021, the depreciation rates ranged from a low of 1.37% to a high of 12.15%. The weighted-average depreciation rate was 2.87% in 2021 and 2.84% in 2020.

Asset Retirement Obligations

APS has AROs for its Palo Verde nuclear facilities and certain other generation assets. The Palo Verde ARO primarily relates to final plant decommissioning. This obligation is based on the Nuclear Regulatory Commission ("NRC's") requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation AROs primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term and coal ash pond closures. Some of APS's transmission and distribution assets have AROs because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the ARO related to such transmission and distribution assets. Additionally, APS has aquifer
protection permits for some of its generation sites that require the closure of certain facilities at those sites. See Note 13 for further information on Asset Retirement Obligations.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and an allowed return on the equity funds used for construction of regulated utility plant. Both the debt and equity components of AFUDC are non-cash amounts within the Comparative Statements of Income. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 6.75% for 2021 and 6.72% for 2020. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed, and the property is placed in service.

On June 30, 2020, FERC issued an order granting a waiver request related to the existing AFUDC rate calculation beginning March 1, 2020, through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. On September 21, 2021, it was further extended until March 21, 2022. The order provides a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS has adopted this simplified approach to computing the AFUDC composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and has left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacts the AFUDC composite rate in 2020 and 2021 but does not impact prior years. Furthermore, the change in the composite rate calculation does not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements.

Materials and Supplies

APS values materials, supplies and fossil fuel inventory using a weighted-average cost method. APS materials, supplies and fossil fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered.

Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, investments held in the nuclear decommissioning trust and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefits plans. Due to the short-term nature of short-term borrowings, the carrying values of these instruments approximate fair value. Fair value measurements may also be applied on a nonrecurring basis to other assets and liabilities in certain circumstances such as impairments. We also disclose fair value information for our long-term debt, which is carried at amortized cost. See Note 8 for additional information.

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market which we can access for the asset or liability in an orderly transaction between willing market participants on the measurement date. Inputs to fair value may include observable and unobservable data. We maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

We determine fair market value using observable inputs such as actively-quoted prices for identical instruments when available. When actively-quoted prices are not available for the identical instruments, we use other observable inputs, such as prices for similar instruments, other corroborative market information, or prices provided by other external sources. For options, long-term contracts, and other contracts for which observable price data are not available, we use models and other valuation methods, which may incorporate unobservable inputs to determine fair market value.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. See Note 14 for additional information about fair value measurements.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial instruments including futures, forwards, options, and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and natural gas. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power expenses in our Comparative Statements of Income, but does not impact our financial condition, net income, or cash flows.

We account for our derivative contracts in accordance with derivatives and hedging guidance, which requires all derivatives not qualifying for a scope exception to be measured at fair value on the balance sheet as either assets or liabilities. Transactions with counterparties that have master netting arrangements are reported gross on the balance sheet. See Note 16 for additional information about our derivative instruments.

Loss Contingencies and Environmental Liabilities

APS is involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses and environmental liabilities are recorded when it is determined that it is probable that a loss has occurred, and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, APS records a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan for the employees of Pinnacle West and its subsidiaries, in addition to a non-qualified pension plan. Pinnacle West also sponsors another postretirement benefit plan for the employees of Pinnacle West and its subsidiaries that provides medical and life insurance benefits to retired employees. Pension and other postretirement benefit expense are determined by actuarial valuations, based on assumptions that are evaluated annually. See Note 9 for additional information on pension and other postretirement benefits.

Nuclear Fuel

APS amortizes nuclear fuel by using the unit-of-production method. The unit-of-production method is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The Department of Energy ("DOE") is responsible for the permanent disposal of spent nuclear fuel and charged APS $0.001 per kWh of nuclear generation through May 2014, at which point the DOE reduced the fee to zero. In accordance with a settlement agreement with the DOE in August 2014 for interim storage, we now accrue a receivable and an offsetting regulatory liability through the settlement period ending December of 2022. See Note 12 for information on spent nuclear fuel disposal costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by guidance relating to accounting for income taxes and are based on currently enacted tax rates. Pinnacle West Capital Corporation files our federal income tax return on a consolidated basis, and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each first-tier subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. See Note 6 for additional discussion.

Cash and Cash Equivalents

We consider cash equivalents to be highly liquid investments with a remaining maturity of three months or less at acquisition.

The following table summarizes supplemental APS cash flow information for each of the last two years (dollars in thousands):

	Year ended December 31,	
	2021	2020
Cash paid during the period for:		
Income taxes, net of refunds	$ 19,783	$ 41,176
Interest, net of amounts capitalized	217,749	206,328
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 167,657	$ 113,502
Dividends accrued but not yet paid	96,000	93,500

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets, primarily software. The intangible assets are amortized over their finite useful lives. Amortization expense was $80 million in 2021 and $70 million in 2020. Estimated amortization expense on existing intangible assets over
the next five years is $75 million in 2022, $63 million in 2023, $44 million in 2024, $33 million in 2025, and $27 million in 2026. At December 31, 2021, the weighted-average remaining amortization period for intangible assets was 6 years.

Investments

Our investments in the nuclear decommissioning trusts, coal reclamation escrow accounts and active union employee medical account, are accounted for in accordance with guidance on accounting for investments in debt and equity securities. See Notes 14 and 18 for more information on these investments.

Leases

We determine if an agreement is a lease at contract inception. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To control the use of an identified asset an entity must have both a right to obtain substantially all of the benefits from the use of the asset and the right to direct the use of the asset.
If we determine an agreement is a lease, and we are the lessee, we recognize a right-of-use lease asset and a lease liability at the lease commencement date. Lease liabilities are recognized based on the present value of the fixed lease payments over the lease term. To present value lease liabilities we use the implicit rate in the lease if the information is readily available, otherwise we use our incremental borrowing rate determined at lease commencement. Our incremental borrowing rate is based on the rate of interest we would have to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. When measuring right-of-use assets and lease liabilities we exclude variable lease payments, other than those that depend on an index or rate or are in-substance fixed payments. For short-term leases with terms of 12 months or less, we do not recognize a right-of-use lease asset or lease liability. We recognize operating lease expense using a straight-line pattern over the periods of use.

APS enters into purchased power contracts that may contain leases. This occurs when a purchased power agreement designates a specific power plant, APS obtains substantially all of the economic benefits from the use of the plant and has the right to direct the use of the plant. Purchased power lease contracts may also include energy storage facilities. Lease costs relating to purchased power lease contracts are reported in fuel and purchased power on the Comparative Statements of Income and are subject to recovery under the Power Supply Adjustor ("PSA") or Renewable Energy Standard ("RES"). See Note 5. We also may enter into lease agreements related to vehicles, office space, land, and other equipment. See Note 10 for information on our lease agreements.

Preferred Stock

At December 31, 2021, APS had 15,535,000 shares of various types of preferred stock authorized with $25, $50, and $100 par values, none of which was outstanding.

Subsequent Events

Management evaluates events or transactions that occur after the balance sheet date, but before the financial statements are issued or available to be issued for potential recognition or disclosures in the financial statements as required by GAAP. We have evaluated subsequent events for recognition in the financial statements through February 25, 2022, which is the date the financial statements, prepared in accordance with GAAP were issued. Management updated such evaluation for disclosure purposes through
March 16, 2022. The accompanying statements contain all adjustments and disclosures necessary for fair presentation.

3. Revenue

Sources of Revenue

The following table provides detail of revenue disaggregated by revenue sources (dollars in thousands):

	Year Ended December 31,		
	2021	2020	
Retail Electric Service			
Residential	$ 1,913,324	$ 1,929,178	(a)
Non-Residential	1,586,940	1,486,098	
Wholesale Energy Sales	214,111	102,793	
Transmission Services for Others	99,406	66,156	
Other Sources	10,121	7,759	
Total Operating Revenues	$ 3,823,902	$ 3,591,984	

(a) Residential revenues for the year ended December 31, 2020, reflect a $24 million reduction related to the Arizona Attorney General matter. See Note 12.

Retail Electric Revenue. Retail electric revenue is generated by the sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the ACC and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 21 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms.

Wholesale Energy Sales and Transmission Services for Others. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities primarily consist of managing fuel and purchased power risks in connection with the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the year ended December 31, 2021 and 2020 were $3,780 million and $3,538 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the year ended December 31, 2021 and 2020 our revenues that do not qualify as revenue from contracts with customers were $44 million and $54 million, respectively. This relates primarily to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 5 for a discussion of our regulatory cost recovery mechanisms.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Comparative Balance Sheets as of December 31, 2021 or December 31, 2020.

Allowance for Doubtful Accounts

On March 13, 2020, due to the COVID-19 pandemic we voluntarily suspended disconnections of customers for nonpayment. The suspension of customer disconnections was extended from March 13, 2020, through December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and certain customers with past due balances were placed on eight-month payment arrangements. During this time, our disconnection policies were also impacted by the Summer Disconnection Moratorium. These circumstances and the on-going COVID-19 pandemic continue to impact our allowance for doubtful accounts including our write-off factor. We continue to monitor the impacts of COVID-19, our disconnection policies, summer moratorium, payment arrangements, among other considerations impacting our estimated write-off factor and allowance for doubtful accounts. See Note 1 for our accounting policies on allowance for doubtful accounts. See Note 5 for additional discussion on the COVID-19 pandemic and the Summer Disconnection Moratorium.

The following table provides a rollforward of the allowance for doubtful accounts (dollars in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020
Allowance for doubtful accounts, balance at beginning of period	$ 19,782	$ 8,171
Bad debt expense	22,251	20,633
Actual write-offs	(16,679)	(9,022)
Allowance for doubtful accounts, balance at end of period	$ 25,354	$ 19,782

4. New Accounting Standards

ASU 2021-05, Leases: Certain Leases with Variable Lease Payments

In July 2021, a new accounting standard was issued that amends the lease accounting guidance. The amended guidance will require lessors to account for certain lease transactions, that contain variable lease payments, as operating leases. The amendments are intended to eliminate the recognition of any day-one loss associated with certain sales-type and direct-financing lease transactions. The changes do not impact lessee accounting. The standard may be adopted using either a prospective or modified retrospective approach. We adopted this standard on January 1, 2022 using a prospective approach. The adoption of this standard did not impact our financial statements.

5. Regulatory Matters

COVID-19 Pandemic

During 2020 and 2021, APS implemented several programs and initiatives to help our customers deal with the economic and other impacts of the COVID-19 pandemic, including but not limited to the following:

- *Suspension of Disconnections; Waiver of Late Payment Fees*. APS voluntarily suspended disconnections of customers for nonpayment beginning March 13, 2020, until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and customers with past due balances of $75 or greater as of that date were automatically placed on eight-month payment arrangements. APS voluntarily began waiving late payment fees of its customers on March 13, 2020 and is continuing to waive late payment fees. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium (defined below) and the related write-offs of customer delinquent accounts.

- *COVID-19 Emergency Relief Package*. On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the Demand Side Management ("DSM") Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption, which was different than actual consumption during the refund period.

- *COVID Customer Support Fund*. In 2020, APS spent more than $15 million to assist customers and local non-profits and community organizations to help with the impact of the COVID-19 pandemic, with $12.4 million of these dollars directly committed to bill assistance programs (the "COVID Customer Support Fund"). The COVID Customer Support Fund was comprised of (i) approximately $8.8 million in funds that are not recoverable through rates, and (ii) an additional $3.6 million in bill credits for limited income customers ordered by the ACC in December 2020, of which 50%, up to a maximum of $2.5 million, was committed to be funds that are not recoverable through rates, with the remaining bill credits being deferred for potential future recovery in rates. Included in the COVID Customer Support Fund were programs that assisted customers with a delinquency of two or more months, providing a one-time credit of $100, an expanded credit of $300 for limited income customers, programs to assist extra small and small non-residential customers with a one-time credit of $1,000, and other targeted programs allocated to assist with other COVID-19 needs in support of utility bill assistance. The December 2020 ACC order further assisted delinquent limited income customers with an additional bill credit of up to $250 or their delinquent balance, whichever was less. APS has distributed all funds for all COVID Customer Support Fund programs combined. Beyond the COVID Customer Support Fund, APS has also provided $2.7 million to assist local non-profits and community organizations working to mitigate the impacts of the COVID-19 pandemic.

- *Deferral of PSA Rate Increase*. In February 2021, APS delayed the annual reset of the PSA, with 50% of the PSA rate increase taking effect in April 2021 and the remaining 50% taking effect in November 2021. See below for discussion of the PSA.

2019 Retail Rate Case

APS filed an application with the ACC on October 31, 2019 (the "2019 Rate Case") seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project that was the subject of a separate proceeding. See "Four Corners SCR Cost Recovery" below. It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the Tax Expense Adjustor Mechanism ("TEAM"). The proposed total annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure		Cost of Capital	
Long-term debt	45.3	%	4.10	%
Common stock equity	54.7	%	10.15	%
Weighted-average cost of capital			7.41	%

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.030168 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- authorization to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- a number of proposed rate and program changes for residential customers, including:

- a super off-peak period during the winter months for APS's time-of-use with demand rates;
- additional $1.25 million in funding for APS's limited-income crisis bill program; and
- a flat bill/subscription rate pilot program;

- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;
- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Plant. See "Navajo Plant" below.

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommended, among other things, (i) a $89.7 million revenue increase, (ii) an average annual customer bill increase of 2.7%, (iii) a return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) the recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) the recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommended, among other things, (i) a $20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, a (i) $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism, to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition ("CCT") plan related to the closure or future closure of coal-fired generation facilities, of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020 financials. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, and this amount was recognized in our December 31, 2021 financials.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%. The hearing concluded on March 3, 2021 and the post-hearing briefing concluded on April 30, 2021.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the RES adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20 basis point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m., but did not explicitly approve the 10 months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by April 1, 2022. On January 12, 2022, the ACC voted to extend the deadline until September 1, 2022, to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

APS expects to file an application with the ACC for its next general retail rate case by mid-year 2022 but is continuing to evaluate the timing of such filing.

Information Technology ACC Investigation

On December 16, 2021, the ACC opened an investigation into various matters related to APS's Information Technology department, including information about technology projects, costs, vendor management leadership and decision making. APS is cooperating with the investigation. The ACC Staff has been directed to report to the ACC on the investigation in April 2022. APS cannot predict the outcome of this matter.

2016 Retail Rate Case Filing

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, the RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules.

Other key provisions of the 2017 Settlement Agreement include the following:

- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing SCR equipment at Four Corners;
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the PSA to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as APS Solar Communities) for utility-owned solar distributed generation ("DG") with the purpose of expanding access to rooftop solar for low- and moderate-income Arizonans, recoverable through the RES, to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
  - a change in the on-peak time-of-use period from noon to 7 p.m. to 3 p.m. to 8 p.m. Monday through Friday, excluding holidays;
  - non-grandfathered DG customers would be required to select a rate option that has time-of-use rates and either a new grid access charge or demand component;
  - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027, for combined-cycle generating units), unless expressly authorized by the ACC.

On August 15, 2017, the ACC approved the 2017 Settlement Agreement without material modifications and on August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"). The new rates went into effect on August 19, 2017.

See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas, and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget. In 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2020. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2020. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 DSM Plan.

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its integrated resource planning ("IRP"), and seek cost recovery in a rate process. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source requests for proposals ("RFP") requirements and the IRP process. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget includes funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the 2019 Rate Case decision. APS's budget proposal supports existing approved projects and commitments and requests a permanent waiver of the RES residential and non-residential distributed energy requirements for 2022. The ACC has not yet ruled on the 2022 RES Implementation Plan.

Demand Side Management Adjustor Charge. The ACC Energy Efficiency Standard ("EES") requires APS to submit a Demand Side Management Implementation Plan ("DSM Plan") annually for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its Lost Fixed Cost Recovery ("LFCR") mechanism. See below for discussion of the LFCR.

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the DSM portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan sought a requested budget of $52.6 million and requested a waiver of the Electric Energy Efficiency
Standard for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels but kept the overall budget at $52.6 million.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption during the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, as described below.

On December 31, 2020, APS filed its 2021 DSM Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Plan that proposed an additional performance incentive for customers participating in the residential energy storage pilot program approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Plan.

On April 20, 2021, APS filed a request to extend the June 1, 2021 deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved the request, granting an extension until 120 days after the ACC action on the 2021 DSM Plan, or December 31, 2021, whichever is later. On December 17, 2021, APS filed its 2022 DSM Plan which requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;
- an adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- the PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- the PSA rate includes (a) a "forward component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "historical component," under which differences between actual fuel and purchased power costs and those recovered or refunded through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "transition component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and
- the PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2021 and 2020 (dollars in thousands):

	Twelve Months Ended December 31,	
	2021	2020
Beginning balance	$ 175,835	$ 70,137
Deferred fuel and purchased power costs - current period	256,871	93,651
Amounts refunded/(charged) to customers	(44,558)	12,047
Ending balance	$ 388,148	$ 175,835

The PSA rate for the PSA year beginning February 1, 2019, was $0.001658 per kWh, as compared to the $0.004555 per kWh for the prior year. This rate was comprised of a forward component of $0.000536 per kWh and a historical component of $0.001122 per kWh. This represented a $0.002897 per kWh decrease compared to 2018. These rates went into effect as filed on February 1, 2019.

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh, which consisted of a forward component of $(0.002086) per kWh and a historical component of $0.001630 per kWh. The 2020 PSA rate is a $0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh, which consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the PSA rate increase taking effect in April 2021 and the remaining 50%

the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the PSA rate increase taking effect in April 2021 and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a PSA rate of $0.003544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit, which is currently underway, to better understand the factors that contributed to the increase in fuel costs. APS cannot predict the outcome of this audit.

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate is a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022. At the time of the compliance filing, the amount remaining over the annual cap was approximately $365 million of fuel and purchased power costs which will be reflected in future year resets of the PSA.

On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA. On December 29, 2020, the ACC Staff filed its report and recommended the storage costs be included in the PSA once the systems are in-service. On January 12, 2021, the ACC approved this application but did not rule on the prudency. On October 28, 2021, APS filed an application requesting approval to recover costs related to three additional energy storage projects through the PSA once the systems are in service. On December 16, 2021, the ACC approved this application but did not rule on the prudency. APS cannot predict the outcome of this matter.

Environmental Improvement Surcharge ("EIS"). The EIS permits APS to recover the capital carrying costs (rate of return, depreciation, and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2022 application requested an increase in the charge to $11.4 million, or $1.1 million over the prior-period charge, and it will become effective with the first billing cycle in April 2022 absent the ACC taking action.

Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the Transmission Cost Adjustor ("TCA"). Under the terms of the settlement agreement entered into in 2012 regarding APS's rate case ("2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. APS reviews the proposed formula rate filing amounts with the ACC Staff. Any items or adjustments which are not agreed to by APS and the ACC Staff can remain in dispute until settled or litigated with FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 17, 2020, APS made a filing to make modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Act, as well as for future local, state, and federal statutory tax rate changes. APS amended its March 17, 2020 filing on April 28, 2020, September 29, 2021, and October 27, 2021. In January 2022, FERC approved APS's modifications to its annual transmission formula.

Effective June 1, 2019, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $25.8 million for the 12-month period beginning June 1, 2019, in accordance with the FERC-approved formula. Of this amount, wholesale customer rates increased by $21.1 million and retail customer rates would have increased by approximately $4.7 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved TCA balancing account, the retail revenue requirement increased by a total of $4.9 million, resulting in a decrease to residential rates and an increase to commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2019.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the 12-month period beginning June 1, 2020, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential and 2.68 cents non-residential kWh as set forth in the 2019 Rate Case decision. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). On July 10, 2019, the ACC approved APS's 2019 LFCR adjustment as filed, effective with the next billing cycle of July 2019. On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment, thus the previously approved rates continue to remain intact. The $11.8 million will continue to be maintained in the LFCR regulatory asset balancing account and will be included in APS's next LFCR application filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism as a result of the 2019 Rate Case decision did not materially impact its results of operations and financial statements for the year ended December 31, 2021.

On February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels). The ACC's final determination of APS's 2022 annual LFCR adjustment filing and related earnings test may materially impact the timing and amounts of future LFCR revenue recognition. See Note 3 for a discussion of alternative revenue program accounting treatment related to certain regulatory cost recovery mechanisms and see the Regulatory Assets and Liabilities table below. APS cannot predict the outcome or timing of the ACC's consideration and final determination of its 2022 annual LFCR adjustment filing.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On August 13, 2018, APS filed a request with the ACC that addressed the return of $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 will be recorded as a part of the balancing account and will be addressed for recovery as part of the 2019 Rate Case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit are recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which will provide an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of the 2019 Rate Case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit are recognized based upon APS's seasonal kWh sales pattern.

As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021 and all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS's next rate case.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a Resource Comparison Proxy ("RCP") methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-

scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to September 1, 2017, based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies.

In accordance with the 2017 Rate Case Decision, APS filed its request for an export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021.

See "2016 Retail Rate Case Filing" above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

After various proceedings between September 2016 and March 2020, at which time Burns' appeal of a prior dismissal by the trial court was pending before the Arizona Court of Appeals, Burns' position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. On March 4, 2021, the Court of Appeals found Burns' motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day.

In its March 4, 2021, opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021, requesting that the petition be denied. The Arizona Supreme Court granted Burns' petition and oral argument is scheduled for March 8, 2022. Pinnacle West and APS cannot predict the outcome of this matter.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and subsequent drafts were filed by ACC Staff in July 2019, February 2020, and July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. A new EES was not included in the proposed rules. These rules would have required utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, these rules would have changed the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS's IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by 2030 and authorizing future rate base treatment of qualifying demand-side resources as proposed in future rate cases. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year PPAs ("Power Purchase Agreement") with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

On July 16, 2020, FERC issued a final rule revising FERC's regulations implementing PURPA. The final rule went into effect on December 31, 2020.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur and customers will have four months to pay back their deposit and any remaining delinquent amounts. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method (June 1 – October 15) for disconnection moratoriums. On November 2, 2021, the ACC approved the final rules, and on November 23, 2021, the rules were submitted to the Arizona Office of the Attorney General for final review and approval. Although the rules are not yet final, APS intends to employ the calendar method for its disconnection moratorium. This is consistent with APS's existing disconnection moratorium processes since 2019.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. At the same time, the Arizona legislature is considering a bill that would nullify, if approved, a 20-year-old electric deregulation law that has been in place since 1998. The bill has several procedural steps in the legislative process before becoming law. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which has been returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law
Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. The ACC did not issue a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Rate Case filing with the ACC.

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2021. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See above for further discussion on the 2019 Rate Case decision.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of Cholla and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS has committed to end the use of coal at its remaining Cholla units by 2025.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs ($41.8 million as of December 31, 2021), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allows for decommissioning activities to begin after the plant ceased operations. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset.

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant ($62.2 million as of December 31, 2021), in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset ($16.8 million as of December 31, 2021). The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in thousands):

	December 31,	
	2021	2020
Pension (a)	$ 509,751	$ 469,953
Deferred fuel and purchased power (b) (c)	388,148	175,835
Income taxes - AFUDC equity	172,393	165,945
Ocotillo deferral (e)	147,650	95,723
Retired power plant costs	114,841	142,395
SCR Deferral (e)(f)	105,771	81,307
Lost Fixed Cost Recovery (b)	63,889	41,807
Deferred property taxes	49,626	58,196
Deferred compensation	33,997	36,195
Income taxes — investment tax credit basis adjustment	24,768	25,404
Four Corners cost deferral	24,075	32,152
Coal reclamation	16,840	18,067
Mead-Phoenix transmission line CIAC	9,380	9,712
Deficient deferred income taxes – FERC-tax Cuts and Jobs Act (g)	8,528	9,062
Tax expense adjustor mechanism (b)	6,501	6,226
TCA balancing account (b)	3,834	—
Tax expense of Medicare subsidy	3,704	4,939

Deficient deferred income taxes - ACC-Tax Cuts and Jobs Act (g)	2,772	2,886
Demand side management	919	7,268
AG-1 deferral	—	2,716
Deferred fuel and purchased power — mark-to-market (Note 16)	—	12,585
Other	3,187	6,457
Total regulatory assets (d)	$ 1,690,574	$ 1,404,830

(a) This asset represents the future recovery of pension benefit obligations and expense through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI ("Other comprehensive income") and result in lower future revenues. As a result of the 2019 Rate Case Decision, the amount authorized for inclusion in rate base was determined using an averaging methodology, which resulted in a reduced return in retail rates. See Note 9 for further discussion.
(b) See “Cost Recovery Mechanisms” discussion above.
(c) Subject to a carrying charge.
(d) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in “Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters.”
(e) Balance includes amounts for future regulatory consideration and amortization period determination.
(f) See “Four Corners SCR Cost Recovery” discussion above.
(g) For purposes of presentation on the Statement of Cash Flows, amortization of the regulatory assets for excess deferred income taxes are reflected as “Deferred income taxes” under Cash Flows From Operating Activities. The balances at December 31, 2021 and December 31, 2020 include $2.8 million and $2.9 million related to protected deficient deferred incomes taxes and $8.5 million and $9 million related to unprotected deficient deferred income taxes, respectively.

The detail of regulatory liabilities is as follows (dollars in thousands):

	December 31,	
	2021	2020
Excess deferred income taxes - ACC - Tax Cuts and Job Act (a)	$ 1,015,221	$ 1,056,799
Asset retirement obligations	614,683	506,049
Other postretirement benefits (d)	374,815	387,293
Excess deferred income taxes - FERC - Tax cuts and Jobs Act (a)	237,644	245,449
Deferred fuel and purchased power — mark-to-market (Note 16)	107,602	—
Income taxes - change in rates	67,553	70,394
Four Corners coal reclamation	55,391	54,895
Income taxes - deferred investment tax credit	49,601	50,879
Spent nuclear fuel	45,282	50,989
Renewable energy standard (b)	38,640	39,545
FERC transmission true up	34,304	9,605
Removal costs (c)	26,529	25,144
Property tax deferral	20,192	13,856
Sundance maintenance	13,797	14,497
Demand side management (b)	5,417	10,819
Tax expense adjustor mechanism (b) (e)	4,835	7,089
Deferred gains on utility property	1,852	3,967
TCA balancing account (b)	—	7,574
Active union medical trust	—	6,057
Other	182	486
Total regulatory liabilities	$ 2,713,540	$ 2,561,386

(a) For purposes of presentation on the Statement of Cash Flows, amortization of the regulatory liabilities for excess deferred income taxes are reflected as “Deferred income taxes” under Cash Flows From Operating Activities. Balances at December 31, 2021 and December 31, 2020 include $1,216 million and $1,263 million related to protected excess deferred incomes taxes and $37 million and $39 million related to unprotected excess deferred income taxes, respectively
(b) See “Cost Recovery Mechanisms” discussion above.
(c) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.
(d) See Note 9.
(e) Balance includes amounts for future regulatory consideration and amortization period determination.

6. Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statement purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using currently enacted income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Comparative Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction, investment tax credit ("ITC") basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to the change in income tax rates and deferred taxes resulting from ITCs.

The Tax Act reduced the corporate tax rate to 21% effective January 1, 2018. As a result of this rate reduction, the Company recognized a $1.14 billion reduction in its net deferred income tax liabilities (FERC accounts 282, 283, 190) as of December 31, 2017.

In accordance with accounting for regulated companies, the effect of this rate reduction was substantially offset by a net regulatory liability. As of December 31, 2017 to reflect the $1.14 billion reduction in its net deferred income tax liabilities (FERC accounts 282, 283, and 190) caused by the rate reduction, APS recorded a net regulatory liability of $1.52 billion (FERC accounts 254 and 182.3) and a $377 million net deferred tax asset (FERC accounts 190, 282, and 283). The company amortizes the net regulatory liability (FERC accounts 410.1 and 411.1) in accordance with applicable federal income tax laws which require the amortization of a majority of the balance over the remaining regulatory life of the related property. As a result of the modifications made to the annual transmission formula rate during the second quarter of 2018, the Company began amortization of FERC jurisdictional net excess deferred tax liabilities in 2018. On March 13, 2019, the ACC approved the Company's proposal to amortize non-depreciation related net excess deferred tax liabilities subject to its jurisdiction over a twelve-month period. As a result, the Company began amortization in March 2019. The Company recorded $14 million of income tax benefit related to the amortization of these non-depreciation related net excess deferred tax liabilities as of March 31, 2020, with these non-depreciation related net excess deferred tax liabilities being fully amortized as of March 31, 2020. On October 29, 2019, the ACC approved the Company's proposal to amortize depreciation related net excess deferred tax liabilities subject to its jurisdiction over a 28.5-year period with amortization to retroactively begin as of January 1, 2018. The Company recorded $31 million of income tax benefit related to amortization of these depreciation related net excess deferred tax liabilities for the periods ending December 31, 2021 and December 31, 2020. See Note 5 for more details.

In accordance with regulatory requirements, APS ITCs are deferred and are amortized over the life of the related property with such amortization applied as a credit to reduce current income tax expense in the Statements of Income.

The components of APS’s income tax expense are as follows (dollars in thousands):

	Year Ended December 31,	
	2021	2020

Current:		
Federal	$ 3,203	$ 57,715
State	(11)	99
Total current	3,192	57,814
Deferred:		
Federal	100,021	14,440
State	22,875	16,244
Total deferred	122,896	30,684
Total income tax expense	$ 126,088	$ 88,498

On the APS Comparative Statements of Income, federal and state income taxes are allocated between operating income and other income.

The following chart compares APS's pretax income at the 21% statutory federal income tax rate to income tax expense (dollars in thousands):

	Year Ended December 31,	
	2021	2020
Federal income tax expense at statutory rate	$ 159,145	$ 137,926
Increases (reductions) in tax expense resulting from:		
State income tax net of federal income tax benefit	23,339	20,124
State income tax credits net of federal income tax benefit	(5,277)	(7,213)
Excess deferred income taxes - Tax Cuts and Jobs Act	(36,558)	(50,543)
Allowance for equity funds used during construction (see Note 2)	(4,180)	(2,747)
Investment tax credit amortization	(7,620)	(7,510)
Other	(2,761)	(1,539)
Income tax expense	$ 126,088	$ 88,498

The components of the net deferred income tax liability were as follows (dollars in thousands):

	December 31,	
	2021	2020
DEFERRED TAX ASSETS		
Risk management activities	$ 1,848	$ 5,343
Regulatory liabilities:		
Excess deferred income taxes - Tax Cuts and Jobs Act	309,708	322,046
Asset retirement obligation and removal costs	151,950	125,146
Unamortized investment tax credits	49,601	50,879
Other postretirement benefits	92,654	95,778
Other	65,784	43,799
Operating lease liabilities	204,378	107,414
Pension liabilities	37,814	40,168
Coal reclamation liabilities	43,165	42,065
Renewable energy incentives	22,646	25,355
Credit and loss carryforwards	27,885	16,134
Other	74,184	78,113
Total deferred tax assets	1,081,617	952,240
DEFERRED TAX LIABILITIES		
Plant-related	(2,566,397)	(2,477,515)
Risk management activities	(28,447)	(2,230)
Pension and other postretirement assets	(132,769)	(122,580)
Other special use funds	(64,610)	(42,927)
Operating lease right-of-use assets	(204,378)	(107,414)
Regulatory assets:		
Deficient deferred income taxes - Tax Cuts and Jobs Act	(2,793)	(2,955)
Allowance for equity funds used during construction	(42,616)	(41,038)
Deferred fuel and purchased power	(96,033)	(47,673)
Pension benefits	(126,010)	(116,219)
Retired power plant costs	(28,389)	(35,214)
Other	(123,871)	(106,475)
Other	(6,809)	(5,514)
Total deferred tax liabilities	(3,423,122)	(3,107,754)
Deferred income taxes — net	$ (2,341,505)	$ (2,155,514)

As of December 31, 2021, APS's deferred tax assets for credit and loss carryforwards relate to state credit carryforwards net of federal benefit of $24 million, which first begin to expire in 2024 and Arizona net operating loss net of federal benefit of $4 million, which will expire in 2041.

7. Lines of Credit and Short-Term Borrowings

APS maintains committed revolving credit facilities in order to enhance liquidity and provide credit support for its commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

The table below presents the consolidated credit facilities and the amounts available and outstanding (dollars in thousands):

	December 31, 2021	December 31, 2020
Commitments under Credit Facilities	$ 1,000,000	$ 1,000,000
Outstanding Commercial Paper, Term Loan and Revolving Credit Facility Borrowings	(278,700)	—
Amount of Credit Facilities Available	$ 721,300	$ 1,000,000
Weighted-Average Commitment Fees	0.125%	0.100%

On May 28, 2021, APS replaced its two $500 million revolving credit facilities that would have matured in June 2022 and July 2023, respectively, with two new $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings and the agreements include a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2021, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $279 million of outstanding commercial paper borrowings.

See "Financial Assurances" in Note 12 for a discussion of other outstanding letters of credit.

Debt Provisions

On December 17, 2020, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). See Note 8 for additional long-term debt provisions.

8. Long-Term Debt and Liquidity Matters

All of APS's debt is unsecured. The following table presents the components of long-term debt on the Comparative Balance Sheets outstanding (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2021	December 31, 2020
Pollution control bonds:				
Variable	2029	(b)	$ 35,975	$ 35,975
Total pollution control bonds			35,975	35,975
Other long-term debt	2024-2050	2.20%-6.88%	6,310,577	5,862,534
Unamortized discount			(14,995)	(15,900)
Unamortized premium			13,575	14,781
Total long-term debt			6,345,132	5,897,390

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.
(b) The weighted-average rate for the variable rate pollution control bonds was 0.22% at December 31, 2021 and 0.18% at December 31, 2020.

The following table shows principal payments due on APS's total long-term debt (dollars in thousands):

	APS
2022	$ —
2023	—
2024	250,000
2025	300,000
2026	250,000
Thereafter	5,546,552
Total	$ 6,346,552

Debt Fair Value

Our long-term debt fair value estimates are classified within Level 2 of the fair value hierarchy. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of December 31, 2021		As of December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total	$ 6,345,132	$ 6,964,196	$ 5,897,390	$ 7,136,324

On August 16, 2021, APS issued $450 million of 2.2% unsecured senior notes that mature December 15, 2031. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper, replenish cash used to fund capital expenditures, and for general corporate purposes.

On December 21, 2021, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

On January 6, 2022, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

See "Lines of Credit and Short-Term Borrowings" in Note 7 and "Financial Assurances" in Note 12 for discussion of APS's separate outstanding letters of credit.

Debt Provisions

APS's debt covenants related to its respective bank financing arrangements include maximum debt to capitalization ratios. APS complies with this covenant. For APS, this covenant requires that the ratio of debt to total capitalization not exceed 65%. At December 31, 2021, the ratio was approximately 50% for APS. Failure to comply with such covenant levels would result in an event of default, which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

None of APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of APS's bank agreements contain "cross- default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. APS does not have a material adverse change restriction for credit facility borrowings.

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On December 17, 2020, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's long-term debt authorization from $5.9 billion to $7.5 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs. See Note 7 for additional short-term debt provisions.

9. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan (The Pinnacle West Capital Corporation Retirement Plan) and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. All new employees participate in the account balance plan. Defined benefit plans specify the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all employees. The supplemental excess benefit retirement plan covers officers of the Pinnacle West and highly compensated employees designated for participation by the Board of Directors. Employees do not contribute to the plans. Pinnacle West calculates the benefits based on age, years of service and pay.

Pinnacle West also sponsors other postretirement benefit plans (Pinnacle West Capital Corporation Group Life and Medical Plan and Pinnacle West Capital Corporation Post-65 Retiree Health Reimbursement Arrangement "HRA") for the employees of Pinnacle West and its subsidiaries. These plans provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plan, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. Pinnacle West retains the right to change or eliminate these benefits.

Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of its plan assets is their fair value at the measurement date. See Note 14 for further discussion of how fair values are determined. Due to subjective and complex judgments, which may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

Under the HRA, included in the other postretirement benefit plan, the Pinnacle West provides a subsidy to retirees to defray the cost of a Medicare supplemental policy. Prior to 2020, we had been assuming a 4.75% escalation of these benefits; however, actual escalation has been significantly less than this assumption. Accordingly, during 2020 and for future periods, the escalation assumption was reduced to 2.00% (see weighted-average assumption table below). This escalation factor assumption change, among other factors, resulted in an increase in the over-funded status of the other postretirement benefit plan as of December 31, 2020. As a result, on January 4, 2021, we initiated the transfer of approximately $106 million of investment assets from the other postretirement benefit plan into the Active Union Employee Medical Account Trust. The Active Union Employee Medical Account is an existing trust account that holds investments restricted for paying active union employee medical costs, see Note 18. The transfer of other postretirement benefit plan investment assets into the Active Union Employee Medical Account permits access to approximately $106 million of assets for the sole purpose of paying active union employee medical benefits. This transfer of investment assets into the Active Union Employee Medical Account is consistent with the terms of a similar 2018 transaction.

A significant portion of the changes in the actuarial gains and losses of Pinnacle West's pension and postretirement plans is attributable to APS and are recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability, see Note 5.

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants) (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2021	2020	2021	2020
Service cost-benefits earned during the period	$ 61,236	$ 56,233	$ 17,796	$ 22,236
Non-service costs (credits):				
Interest cost on benefit obligation	98,566	118,567	16,513	25,857
Expected return on plan assets	(202,628)	(187,443)	(41,444)	(40,077)
Amortization of:				
Prior service credit	—	—	(37,705)	(37,575)
Net actuarial (gain)/loss	15,948	34,612	(10,093)	—
Net periodic benefit cost/(benefit)	$ (26,878)	$ 21,969	$ (54,933)	$ (29,559)
Portion of cost/(benefit) charged to expense	$ (32,743)	$ 3,386	$ (38,657)	$ (20,966)

The following table shows the plans' changes in the benefit obligations and funded status (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2021	2020	2021	2020
Change in Benefit Obligation				
Benefit obligation at January 1	$ 3,902,867	$ 3,613,114	$ 624,034	$ 746,924
Service cost	61,236	56,233	17,796	22,236
Interest cost	98,566	118,567	16,513	25,857
Benefit payments	(207,928)	(191,704)	(31,280)	(31,511)
Actuarial (gain) loss	(137,917)	306,657	(35,222)	(139,472)
Benefit obligation at December 31	3,716,824	3,902,867	591,841	624,034
Change in Plan Assets				
Fair value of plan assets at January 1	3,886,544	3,318,351	961,165	837,494
Actual return on plan assets	18,169	642,373	41,432	150,076
Employer contributions	100,000	100,000	—	—
Benefit payments	(192,672)	(174,180)	(24,310)	(26,405)
Transfer to active union medical account	—	—	(105,852)	—
Fair value of plan assets at December 31	3,812,041	3,886,544	872,435	961,165
Funded Status at December 31	$ 95,217	$ (16,323)	$ 280,594	$ 337,131

The following table shows information for pension plans with an accumulated obligation in excess of plan assets (dollars in thousands):

	As of December 31,	
	2021	2020
Accumulated benefit obligation	161,086	171,672
Fair value of plan assets	—	—

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on an accumulated benefit obligation basis at December 31, 2021 and December 31, 2020, therefore the only pension plan with an accumulated benefit obligation in excess of plan assets in 2021 and 2020 is a non-qualified supplemental excess benefit retirement plan.

The following table shows information for pension plans with a projected benefit obligation in excess of plan assets (dollars in thousands):

	As of December 31,	
	2021	2020
Projected benefit obligation	169,912	182,184
Fair value of plan assets	—	—

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on a projected benefit obligation basis at December 31, 2021 and December 31, 2020, therefore the only pension plan with a projected benefit obligation in excess of plan assets in 2021 and 2020 is a non-qualified supplemental excess benefit retirement plan.

The following table shows the amounts recognized on the Comparative Balance Sheets (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2021	2020	2021	2020
Noncurrent asset	$ 265,129	$ 165,861	$ 280,594	$ 337,131
Current liability	(17,047)	(15,700)	—	—
Noncurrent liability	(152,865)	(166,484)	—	—
Net amount recognized (funded status)	$ 95,217	$ (16,323)	$ 280,594	$ 337,131

The following table shows the details related to accumulated other comprehensive loss (gain) as of December 31, 2021 and 2020 (dollars in thousands).

	Pension Plans		Other Benefits Plans	
	2021	2020	2021	2020
Net actuarial loss (gain)	$ 582,895	$ 552,301	$ (262,352)	$ (237,
Prior service credit	—	—	(114,632)	(152,
APS's portion recorded as a regulatory (asset) liability	(509,751)	(469,953)	374,816	387,
Income tax expense (benefit)	(18,081)	(20,364)	990	1,
Accumulated other comprehensive loss (gain)	$ 55,063	$ 61,984	$ (1,178)	$ (1,

The following table shows the weighted-average assumptions used for both the pension and other benefits to determine benefit obligations and net periodic benefit costs:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,	
	2021	2020	2021	2020
Discount rate – pension plans	2.92 %	2.53 %	2.53 %	3.30 %
Discount rate – other benefits plans	2.98 %	2.63 %	2.63 %	3.42 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %	4.00 %
Expected long-term return on plan assets - pension plans	N/A	N/A	5.30 %	5.75 %
Expected long-term return on plan assets - other benefit plans	N/A	N/A	4.90 %	4.85 %
Initial healthcare cost trend rate (pre-65 participants)	6.00 %	6.50 %	6.50 %	7.00 %
Ultimate healthcare cost trend rate (pre-65 participants)	4.75 %	4.75 %	4.75 %	4.75 %
Number of years to ultimate trend rate (pre-65 participants)	4	5	4	5
Initial and ultimate healthcare cost trend rate (post-65 participants) (a)	2.00 %	2.00 %	2.00 %	4.75 %
Interest crediting rate – cash balance pension plans	4.50 %	4.50 %	4.50 %	4.50 %

(a) See discussion above relating to this assumptions impact on benefit obligations and the January 2021 asset transfer to the Active Union Employee Medical Account.

In selecting the pretax expected long-term rate of return on plan assets, Pinnacle West considers past performance and economic forecasts for the types of investments held by the plan. For 2022, Pinnacle West is assuming a 5.00% long-term rate of return for pension assets and 5.50% (before tax) for other benefit assets, which Pinnacle West believes is reasonable given the asset allocation in relation to historical and expected performance.

In selecting its healthcare trend rates, Pinnacle West considers past performance and forecasts of healthcare costs.

Plan Assets

The Board of Directors has delegated oversight of the pension and other postretirement benefit plans' assets to an Investment Management Committee ("Committee"). The Committee has adopted investment policy statements ("IPS") for the pension and the other postretirement benefit plans' assets. The investment
strategies for these plans include external management of plan assets, and prohibition of investments in Pinnacle West securities.

The overall strategy of the pension plan's IPS is to achieve an adequate level of trust assets relative to the benefit obligations. To achieve this objective, the plan's investment policy provides for mixes of investments including long-term fixed income assets and return-generating assets. The target allocation between return-generating and long-term fixed income assets is defined in the IPS and is a function of the plan's funded status. The plan's funded status is reviewed on at least a monthly basis.

Changes in the value of long-term fixed income assets, also known as liability-hedging assets, are intended to offset changes in the benefit obligations due to changes in interest rates. Long-term fixed income assets consist primarily of fixed income debt securities issued by the U.S. Treasury and other government agencies, U.S. Treasury Futures Contracts, and fixed income debt securities issued by corporations. Long-term fixed income assets may also include interest rate swaps, and other instruments.

Return-generating assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-generating assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments may include investments in real estate, private equity and various other strategies. The plan may also hold investments in return-generating assets by holding securities in partnerships, common and collective trusts and mutual funds.

Based on the IPS, and given the pension plan's funded status at year-end 2021, the target and actual allocation for the pension plan at December 31, 2021 are as follows:

	Target Allocation	Actual Allocation
Long-term fixed income assets	80 %	79 %
Return-generating assets	20 %	21 %
Total	100 %	100 %

The permissible range is within +/-3% of the target allocation shown in the above table, and also considers the plan's funded status.
The following table presents the additional target allocations, as a percent of total pension plan assets, for the return-generating assets:

	Target Allocation
Equities in US and other developed markets	12 %

Equities in emerging markets	4 %
Alternative investments	4 %
Total	20 %

The pension plan IPS does not provide for a specific mix of long-term fixed income assets, but does expect the average credit quality of such assets to be investment grade.

As of December 31, 2021, the asset allocation for other postretirement benefit plan assets is governed by the IPS for those plans, which provides for different asset allocation target mixes depending on the characteristics of the liability. Some of these asset allocation target mixes vary with the plan's funded status.

The following table presents the actual allocations of the investment for the other postretirement benefit plan at December 31, 2021:

	Actual Allocation
Long-term fixed income assets	63 %
Return-generating assets	37 %
Total	100 %

See Note 14 for a discussion on the fair value hierarchy and how fair value methodologies are applied. The plans invest directly in fixed income, U.S. Treasury Futures Contracts, and equity securities, in addition to investing indirectly in fixed income securities, equity securities and real estate through the use of mutual funds, partnerships and common and collective trusts. Equity securities held directly by the plans are valued using quoted active market prices from the published exchange on which the equity security trades, and are classified as Level 1. U.S. Treasury Futures Contracts are valued using the quoted active market prices from the exchange on which they trade, and are classified as Level 1. Fixed income securities issued by the U.S. Treasury held directly by the plans are valued using quoted active market prices, and are classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies are primarily valued using quoted inactive market prices, or quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield, maturity and credit quality. These instruments are classified as Level 2.

Mutual funds, partnerships, and common and collective trusts are valued utilizing a Net Asset Value (NAV) concept or its equivalent. Mutual funds, which includes exchange traded funds (ETFs), are classified as Level 1 and valued using a NAV that is observable and based on the active market in which the fund trades.

Common and collective trusts are maintained by banks or investment companies and hold certain investments in accordance with a stated set of objectives (such as tracking the performance of the S&P 500 Index). The trust's shares are offered to a limited group of investors, and are not traded in an active market. Investments in common and collective trusts are valued using NAV as a practical expedient and, accordingly, are not classified in the fair value hierarchy. The NAV for trusts investing in exchange traded equities, and fixed income securities is derived from the market prices of the underlying securities held by the trusts. The NAV for trusts investing in real estate is derived from the appraised values of the trust's underlying real estate assets. As of December 31, 2021, the plans were able to transact in the common and collective trusts at NAV.

Investments in partnerships are also valued using the concept of NAV as a practical expedient and, accordingly, are not classified in the fair value hierarchy. The NAV for these investments is derived from the value of the partnerships' underlying assets. The plan's partnerships holdings relate to investments in high-yield fixed income instruments. Certain partnerships also include funding commitments that may require the plan to contribute up to $50 million to these partnerships; as of December 31, 2021, approximately $38 million of these commitments have been funded.

The plans' trustee provides valuation of Pinnacle West's plan assets by using pricing services that utilize methodologies described to determine fair market value. Pinnacle West has internal control procedures to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2021, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 821	$ —	$ —	$ 821
Fixed income securities:				
Corporate	—	1,765,623	—	1,765,623
U.S. Treasury	1,008,211	—	—	1,008,211
Other (b)	—	165,496	—	165,496
Common stock equities (c)	209,063	—	—	209,063
Mutual funds (d)	132,656	—	—	132,656
Common and collective trusts:				
Equities	—	—	255,141	255,141
Real estate	—	—	173,197	173,197
Partnerships	—	—	15,730	15,730
Short-term investments and other (e)	—	—	86,103	86,103
Total	$ 1,350,751	$ 1,931,119	$ 530,171	$ 3,812,041
Other Benefits:				
Cash and cash equivalents	$ 121	$ —	$ —	$ 121
Fixed income securities:				
Corporate	—	244,572	—	244,572
U.S. Treasury	287,057	—	—	287,057
Other (b)	—	9,330	—	9,330
Common stock equities (c)	176,024	—	—	176,024
Mutual funds (d)	26,262	—	—	26,262
Common and collective trusts:				
Equities	—	—	96,547	96,547
Real estate	—	—	23,851	23,851
Short-term investments and other (e)	2,517	—	6,154	8,671
Total	$ 491,981	$ 253,902	$ 126,552	$ 872,435

(a) These investments primarily represent assets valued using NAV as a practical expedient, and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities and asset backed securities.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in international common stock equities.
(e) This category includes plan receivables and payables.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2020, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 9,911	$ —	$ —	$ 9,911
Fixed income securities:				
Corporate	—	1,684,782	—	1,684,782
U.S. Treasury	794,571	—	—	794,571
Other (b)	—	112,224	—	112,224
Common stock equities (c)	331,058	—	—	331,058
Mutual funds (d)	262,765	—	—	262,765
Common and collective trusts:				
Equities	—	—	407,522	407,522
Real estate	—	—	191,595	191,595
Partnerships	—	—	22,420	22,420
Short-term investments and other (e)	—	—	69,696	69,696
Total	$ 1,398,305	$ 1,797,006	$ 691,233	$ 3,886,544
Other Benefits:				
Cash and cash equivalents	$ 1,909	$ —	$ —	$ 1,909
Fixed income securities:				
Corporate	—	221,488	—	221,488
U.S. Treasury	258,102	—	—	258,102
Other (b)	—	8,316	—	8,316
Common stock equities (c)	175,605	—	—	175,605
Mutual funds (d)	34,310	—	—	34,310
Common and collective trusts:				
Equities	—	—	94,674	94,674
Real estate	—	—	19,778	19,778
Short-term investments and other (e)	142,995	—	3,988	146,983
Total	$ 612,921	$ 229,804	$ 118,440	$ 961,165

(a) These investments primarily represent assets valued using NAV as a practical expedient, and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in U.S. and international common stock equities.
(e) This category includes plan receivables and payables.

Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. Pinnacle West made contributions to its pension plan totaling $100 million in 2021 and $100 million in 2020. The minimum required contributions for the pension plan are zero for the next three years and Pinnacle West does not expect to make any voluntary contributions during this time. With regard to contributions to its other postretirement benefit plan, Pinnacle West did not make a contribution in 2021 and 2020 and do not expect to make any contributions for the next three years. Pinnacle West was reimbursed $24 million in 2021 and $26 million in 2020 for prior years retiree medical claims from the other postretirement benefit plan trust assets.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter, are estimated to be as follows (dollars in thousands):

Year	Pension Plans	Other Benefits Plans
2022	$ 220,549	$ 31,244
2023	219,132	31,658
2024	221,724	31,486
2025	222,356	30,988
2026	221,709	30,780
Years 2027-2031	1,121,557	151,194

Electric plant participants contribute to the above amounts in accordance with their respective participation agreements.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and its subsidiaries. In 2021, costs related to APS's employees represented 99% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account, Pinnacle West's matching contributions and earnings or losses on their investments. Under this plan, Pinnacle West matches a percentage of the participants' contributions in cash which is then invested in the same investment mix as participants elect to invest their own future contributions. Pinnacle West recorded expenses for this plan of approximately $12 million for 2021 and $11 million for 2020.

10. Leases

We lease certain land, buildings, vehicles, equipment, and other property through rental agreements with varying terms, provisions, and expiration dates. APS also has certain purchased power agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2022 through 2050.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. See Note 17. On April 1, 2021 one of the three leases was amended to extend the lease term and modify the lease payment. The other two leases were not impacted by this amendment. For regulatory reporting purposes, APS accounts for the three Palo Verde Unit 2 leases as operating leases for income statement and cash flow statement purposes, and for balance sheet purposes they are classified as finance leases.

On May 1, 2021, APS had a new purchased power lease contract that commenced, with a lease term expiring on October 31, 2027. On December 31, 2021, APS modified an existing purchased power lease contract that had commenced in June 2020. The lease modification extends the expiration of this lease from September 30, 2025, to October 31, 2031, among other changes. These purchased power lease agreements allow APS the right to the generation capacity from certain natural-gas fueled generators during certain months of each year throughout the term of the arrangements. As APS only has rights to use the assets during certain periods of each year the leases have non-consecutive periods of use. APS does not operate or maintain these leased assets. APS controls the dispatch of these leased assets and is required to pay fixed monthly capacity payments during the periods of use. For these types of leased assets APS has elected to combine both the lease and non-lease payment components and accounts for the entire fixed payment as a lease obligation. These purchased power lease contracts are accounted for as operating leases. The contracts do not contain purchase options or term extension options. In addition to the fixed monthly capacity payment, APS must also pay variable charges based on the actual production volume of the asset. The variable consideration is not included in the measurement of our lease obligation.

The following table provides information related to our lease costs (dollars in thousands):

	For the Year Ended December 31,			
	2021		2020	
Operating Lease Cost - Purchased Power Lease Contracts	$ 105,762		$ 68,883	
Operating Lease Cost - Land, Property, and Other Equipment	18,278		18,223	
Operating Lease Cost - Palo Verde Unit 2 Operating Leases	—		6,847	
Total Operating Lease Cost	124,040		93,953	
Finance Lease Cost - Palo Verde Unit 2 Finance Leases	21,255	(b)	15,896	
Variable lease cost (a)	118,906		122,273	
Short term lease cost	3,802		3,729	
Total lease cost	$ 268,003		$ 235,851	

(a) Primarily relates to purchased power lease contracts.
(b) For regulatory purposes the costs relating to these finance leases are reported as a component of operating expense.

Lease costs are primarily included as a component of operating expenses on our Comparative Statements of Income. Lease costs relating to purchased power lease contracts are recorded in fuel and purchased power on the Comparative Statements of Income and are subject to recovery under the PSA or RES. See Note 5. The tables above reflect the lease cost amounts before the effect of regulatory deferral under the PSA and RES. Variable lease costs are recognized in the period the costs are incurred, and primarily relate to renewable purchased power lease contracts. Payments under most renewable purchased power lease contracts are dependent upon environmental factors, and due to the inherent uncertainty associated with the reliability of the generation source, the payments are considered variable and are excluded from the measurement of lease liabilities and right-of-use lease assets. Certain of our lease agreements have lease terms with non-consecutive periods of use. For these agreements we recognize lease costs during the periods of use. Leases with initial terms of 12 months or less are considered short-term leases and are not recorded on the balance sheet.

The following table provides information related to the maturity of our lease liabilities (dollars in thousands):

	December 31, 2021				
	Finance Leases	Operating Leases			
Year	Palo Verde Unit 2 Finance Lease	Purchased Power Lease Contract	Other Land, Property & Equipment Lease	Total Operating Lease	Total
2022	$ 21,255	$ 103,752	$ 12,729	$ 116,481	$ 137,736
2023	21,255	106,151	10,440	116,591	137,846
2024	21,255	104,315	7,759	112,074	133,329
2025	21,255	106,582	5,837	112,419	133,674
2026	21,255	120,016	4,602	124,618	145,873
Thereafter	148,786	299,594	34,106	333,700	482,486
Total lease commitments	255,061	840,410	75,473	915,883	1,170,944
Less imputed interest	55,331	72,249	16,862	89,111	144,442
Total lease liabilities	$ 199,730	$ 768,161	$ 58,611	$ 826,772	$ 1,026,502

We recognize lease assets and liabilities upon lease commencement. At December 31, 2021, we have various lease arrangements that have been executed but have not yet commenced. These arrangements primarily relate to energy storage assets, with expected lease commencement dates ranging from June 2022 through June 2024, with lease terms expiring through May 2044. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $1.3 billion over the term of the arrangements.

The following tables provide other additional information related to lease liabilities (dollars in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$ 116,451	$ 81,687
Cash paid for amounts included in the measurement of finance lease liabilities — operating cash flows:	21,255	15,896
Right-of-use operating lease assets obtained in exchange for operating lease liabilities:	500,161	441,653
Right-of-use finance lease assets obtained in exchange for operating lease liabilities:	58,469	—

	December 31, 2021		December 31, 2020	
	Finance Leases	Operating Leases	Finance Leases	Operating Leases
Weighted average remaining lease	12 years	8 years	13 years	6 years
Weighted average discount rate	4.14%	2.12%	4.59%	1.76%

(a) Most of our lease agreements do not contain an implicit rate that is readily determinable. For these agreements we use our incremental borrowing rate to measure the present value of lease liabilities. We determine our incremental borrowing rate at lease commencement based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We use the implicit rate when it is readily determinable.

11. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. We are responsible for our share of operating costs which are included in the corresponding operating expenses on our Comparative Statements of Income. We are also responsible for providing our own financing. Our share of operating expenses and utility plant costs related to these facilities is accounted for using proportional consolidation. The following table shows APS's interests in those jointly owned facilities recorded on the Comparative Balance Sheets at December 31, 2021 (dollars in thousands):

	Percent Owned	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:				
Palo Verde Units 1 and 3	29.1 %	$ 1,932,629	$ 1,113,905	$ 28,288
Palo Verde Unit 2 (a)	16.8 %	657,102	384,193	14,084
Palo Verde Common	28.0 % (b)	792,849	334,804	43,690
Palo Verde Sale Leaseback	(a)	351,050	256,884	—
Four Corners Generating Station	63.0 %	1,686,702	608,247	21,515
Cholla Common Facilities (c)	50.5 %	208,709	121,877	1,608
Transmission facilities:				

ANPP 500kV System	33.5 % (b)	133,289	53,708	115
Navajo Southern System	26.8 % (b)	89,895	35,144	1,535
Palo Verde — Yuma 500kV System	25.8 % (b)	23,650	7,188	716
Four Corners Switchyards	60.1 % (b)	73,133	18,637	258
Phoenix — Mead System	17.1 % (b)	39,523	20,150	—
Palo Verde — Rudd 500kV System	50.0 %	96,376	29,426	—
Morgan — Pinnacle Peak System	64.7 % (b)	119,814	23,575	138
Round Valley System	50.0 %	535	180	—
Palo Verde — Morgan System	87.8 % (b)	259,180	27,995	268
Hassayampa - North Gila System	80.0 %	148,039	19,317	—
Cholla 500kV Switchyard	85.7 %	8,287	2,163	5
Saguaro 500kV Switchyard	60.0 %	21,655	13,471	—
Kyrene — Knox System	50.0 %	578	328	—

(a) See Note 17.
(b) Weighted average of interests.
(c) PacifiCorp owns Cholla Unit 4 (see Note 5 for additional information), and APS operated the unit for PacifiCorp. Cholla Unit 4 was retired on December 24, 2020. The common facilities at Cholla are jointly owned.

12. Commitments and Contingencies

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, which required DOE to pay the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. The settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019. On September 1, 2020, APS and DOE entered into an addendum to the settlement agreement allowing for the recovery of costs incurred through December 31, 2022.

APS has submitted seven claims pursuant to the terms of the August 18, 2014 settlement agreement, for seven separate time periods during July 1, 2011 through June 30, 2020. DOE has approved and paid $111.8 million for these claims (APS's share is $32.5 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers (see Note 5). On November 1, 2021, APS filed its eighth claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). In February 2022, the DOE approved this claim.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $13.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers. The remaining balance of approximately $13.1 billion of liability coverage is provided through a mandatory, industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $137.6 million, subject to a maximum annual premium of approximately $20.5 million per incident. Based on APS's ownership interest in the three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $120.1 million, with a maximum annual retrospective premium of approximately $17.9 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $22.4 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. Additionally, at the sole discretion of the NEIL Board of Directors, APS would be liable to provide approximately $63.3 million in deposit premium within 20 days of request as assurance to satisfy any site obligation of retrospective premium assessment. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits, and exclusions.

Fuel and Purchased Power Commitments and Purchase Obligations

APS is party to various fuel and purchased power contracts and purchase obligations with terms expiring between 2022 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $968 million in 2022; $754 million in 2023; $703 million in 2024; $686 million in 2025; $687 million in 2026; and $6.9 billion thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances. These amounts include estimated commitments relating to purchased power lease contracts, see Note 10.

Of the various fuel and purchased power contracts mentioned above, some of those contracts for coal supply include take-or-pay provisions. The current coal contracts with take-or-pay provisions have terms expiring through 2031.

The following table summarizes our estimated coal take-or-pay commitments (dollars in thousands):

	Years Ended December 31,					
	2022	2023	2024	2025	2026	Thereafter
Coal take-or-pay commitments (a)	$ 202,917	$ 201,826	$ 203,638	$ 194,192	$ 195,121	$ 925,644

(a) Total take-or-pay commitments are approximately $1.9 billion. The total net present value of these commitments is approximately $1.5 billion.

APS may spend more to meet its actual fuel requirements than the minimum purchase obligations in our coal take-or-pay contracts. The following table summarizes actual amounts purchased under the coal contracts which include take-or-pay provisions for each of the last two years (dollars in thousands):

	Years Ended December 31,	
	2021	2020
Total purchases	$ 219,958	$ 189,817

Renewable Energy Credits

APS has entered into contracts to purchase renewable energy credits to comply with the RES. APS estimates the contract requirements to be approximately $32 million in 2022; $30 million in 2023; $29 million in 2024; $26 million in 2025; $22 million in 2026; and $87 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

Coal Mine Reclamation Obligations

APS [illegible]

APS must reimburse certain coal providers for final and contemporaneous coal mine reclamation. We account for contemporaneous reclamation costs as part of the cost of the delivered coal. We utilize site-specific studies of costs expected to be incurred in the future to estimate our final reclamation obligation. These studies utilize various assumptions to estimate the future costs. Based on the most recent reclamation studies, APS recorded an obligation for the coal mine final reclamation of approximately $175 million at December 31, 2021 and $170 million at December 31, 2020. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $17 million in 2022; $18 million in 2023; $19 million in 2024; $20 million in 2025; $21 million in 2026; and $48 million thereafter. These funds are held in an escrow account and will be distributed to certain coal providers under the terms of the applicable coal supply agreements. Any amendments to current coal supply agreements may change the timing of the contribution or cost of final reclamation. The annual payments to the escrow account and final distribution to certain coal providers may be subject to adjustments based on escrow earnings.

Superfund-Related Matters

The Comprehensive Environmental Response Compensation and Liability Act (“Superfund” or “CERCLA”) establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (“PRPs”). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 (“OU3”) in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study (“RI/FS”). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS during the first or second quarter of 2022. APS's estimated costs related to this investigation and study is approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District (“RID”) filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID’s groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS’s current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS’s current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation, but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS’s exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID’s CERCLA claims concerning both past and future cost recovery. APS’s share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Arizona Attorney General Matter

APS received civil investigative demands from the Attorney General seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General’s Office in this matter. On February 22, 2021 APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which was returned to customers as restitution.

Four Corners SCR Cost Recovery

As part of APS’s 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2021. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 5 for additional information regarding the Four Corners SCR cost recovery.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases ("GHGs"), water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on Four Corners. Environmental Protection Agency ("EPA") required the plant to install pollution control equipment that constitutes Best Available Retrofit Technology ("BART") to lessen the impacts of emissions on visibility surrounding the plant.

Based on EPA’s final standards, APS’s 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso’s 7% interest in Four Corners Units 4 and 5. 4C Acquisition, LLC ("4CA") purchased the El Paso interest on July 6, 2016. Navajo Transitional Energy Company ("NTEC") purchased the interest from 4CA on July 3, 2018. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest. In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See “Cholla” in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (“RCRA”) and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed “forced closure” or “closure for cause” of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to, either, authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On July 29, 2020, EPA took final action on new regulations establishing revised deadlines for initiating the closure of unlined CCR surface impoundments by April 11, 2021, at the latest. All APS disposal units subject to these closure requirements were closed as of April 11, 2021.

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA’s July 29, 2020 final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS’s application for alternative closure (which would allow the continued disposal of CCR within the facility’s existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025) was submitted to EPA on November 30, 2020 and is currently pending. This application will be subject to public comment and, potentially, judicial review. On January 11, 2022, EPA began issuing proposed decisions pursuant to this provision of the federal CCR regulations and we anticipate receiving a proposed decision with respect to the Cholla facility in 2022.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS’s management of CCR could materially increase, which could affect APS’s financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $30 million and its share of incremental costs to comply with the CCR rule for Cholla is

approximately $16 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan/Affordable Clean Energy Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. Nonetheless, on October 29, 2021, the U.S. Supreme Court announced that it was accepting judicial review of the January D.C. Circuit decision vacating the ACE regulations. While the Biden administration has
expressed an intent to regulate carbon emissions in this sector more aggressively under the Clean Air Act, we cannot at this time predict the outcome of pending EPA rulemaking proceedings or ongoing litigation related to the scope of EPA's authority under the Clean Air Act to regulate carbon emissions from existing power plants.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019 filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. EPA then issued a revised final NPDES permit for Four Corners on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the EAB again took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and the EAB denied the environmental group petition on September 30, 2020. On January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. The September 2019 permit remains in effect pending this appeal. As of November 11, 2021, the parties to this lawsuit, including APS, reached a tentative agreement to settle this matter. Review of this agreement, including public commenting, is currently pending with EPA. Notwithstanding this tentative agreement, we cannot predict the outcome of these appeal proceedings, including further settlement discussions, and, if settlement efforts fail and the appeal is eventually successful, whether that outcome will have a material impact on our financial position, results of operations, or cash flows.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of December 31, 2021, standby letters of credit totaled approximately $0.2 million and will expire in 2022. As of December 31, 2021, surety bonds expiring through 2023 totaled approximately $14 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the
overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

13. Asset Retirement Obligations

In 2021, APS revised its cost estimates for existing AROs at Cholla related to updated estimates for the closure of ponds and facilities, which resulted in an increase to the ARO of approximately $28 million. See additional details in Notes 5 and 12.

In 2020, APS revised its cost estimates for existing AROs at Cholla relating to updated estimates for the closure of ponds and facilities, and at Four Corners and the Navajo Plant relating to corrective action and water monitoring costs, which resulted in an increase to the ARO of $6 million. Also in 2020, an updated Four Corners decommissioning study was finalized for the updated closure date of 2031, which resulted in an increase to the ARO of $13 million.

The following table shows the change in our AROs (dollars in thousands):

	2021	2020
Asset retirement obligations at the beginning of year	$ 705,083	$ 657,218
Changes attributable to:		
Accretion expense	38,437	38,652
Settlements	(4,111)	(9,710)
Estimated cash flow revisions	27,973	18,923
Asset retirement obligations at the end of year	$ 767,382	$ 705,083

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 5.

14. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 — Other significant observable inputs, including quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active, and model-derived valuations whose inputs are observable (such as yield curves).

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category may include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of NAV, as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV as a practical expedient are included in our fair value disclosures; however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 9

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 9 for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for
the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3.

Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account and the active union employee medical account. See Note 18 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustees' and escrow agent's internal operating controls and valuation processes.

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These fixed income instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short-term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trusts' equity security investments are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

The nuclear decommissioning trusts and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid investments are valued using active market prices.

Fair Value Tables

The following table presents the fair value at December 31, 2021 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 115,079	$ —	$ —		$ 115,079
Nuclear decommissioning trust:						
Equity securities	45,264	—	—	(27,782)	(a)	17,482
U.S. commingled equity funds	—	—	—	595,048	(b)	595,048
U.S. Treasury debt	240,745	—	—	—		240,745
Corporate debt	—	203,454	—	—		203,454
Mortgage-backed securities	—	155,574	—	—		155,574
Municipal bonds	—	72,189	—	—		72,189
Other fixed income	—	10,265	—	—		10,265
Subtotal nuclear decommissioning trust	286,009	441,482	—	567,266		1,294,757
Other special use funds:						
Equity securities	47,570	—	—	936	(a)	48,506
U.S. Treasury debt	298,170	—	—	—		298,170
Municipal bonds		11,734	—	—		11,734
Subtotal other special use funds	345,740	11,734	—	936		358,410
Total assets	$ 631,749	$ 568,295	$ —	$ 568,202		$ 1,768,246
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (4,740)	$ (2,738)	$ —		$ (7,478)

(a) Represents net pending securities sales and purchases.
(b) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

The following table presents the fair value at December 31, 2020 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other	Total
Assets					

Risk management activities — derivative instruments:										
Commodity contracts	$	—	$	9,016	$	4	$	—		$ 9,020
Nuclear decommissioning trust:										
Equity securities		29,796		—		—		(17,828)	(a)	11,968
U.S. commingled equity funds		—		—		—		610,055	(b)	610,055
U.S. Treasury debt		164,514		—		—		—		164,514
Corporate debt		—		149,509		—		—		149,509
Mortgage-backed securities		—		99,623		—		—		99,623
Municipal bonds		—		89,705		—		—		89,705
Other fixed income		—		13,061		—		—		13,061
Subtotal nuclear decommissioning trust		194,310		351,898		—		592,227		1,138,435
Other special use funds:										
Equity securities		37,337		—		—		504	(a)	37,841
U.S. Treasury debt		203,220		—		—		—		203,220
Municipal bonds		—		13,448		—		—		13,448
Subtotal other special use funds		240,557		13,448		—		504		254,509
Total assets	$	434,867	$	374,362	$	4	$	592,731		$ 1,401,964
Liabilities										
Risk management activities — derivative instruments:										
Commodity contracts	$	—	$	(20,498)	$	(1,107)	$	—		$ (21,605)

(a) Represents net pending securities sales and purchases.
(b) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote or other characteristics of the product. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment. See Note 5.

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

Financial Instruments Not Carried at Fair Value

The carrying value of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 8 for our long-term debt fair values.

15. Stock-based Compensation

Pinnacle West has incentive compensation plans under which stock-based compensation is granted to officers, key-employees, and non-officer members of the Board of Directors. Awards granted under the 2021 Long-Term Incentive Plan ("2021 Plan") may be in the form of stock grants, restricted stock units, stock units, performance shares, restricted stock, dividend equivalents, performance share units, performance cash, incentive and non-qualified stock options, and stock appreciation rights. The 2021 Plan authorizes up to 1.5 million common shares to be available for grant. As of December 31, 2021, 1.2 million common shares were available for issuance under the 2021 Plan. During 2021 and 2020, the Company granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. Awards granted from 2012 to May 2021 were issued under the 2012 Long-Term Incentive Plan ("2012 Plan"), and awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"). No new awards may be granted under the 2012 or 2007 Plans.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $18 million in 2021 and $18 million in 2020. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $3 million in 2021 and $4 million in 2020.

As of December 31, 2021, there were approximately $11 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. We expect to recognize these costs over a weighted-average period of 2 years.

The total fair value of shares vested was $22 million in 2021and $22 million in 2020.

The following table is a summary of awards granted and the weighted-average grant date fair value for each of the last two years:

	Restricted Stock Units, Stock Grants, and Stock Units (a)		Performance Shares (b)	
	2021	2020	2021	2020
Units granted	152,345	118,403	161,840	122,830
Weighted-average grant date fair value	$ 76.72	$ 71.70	$ 82.42	$ 104.74

(a) Units granted includes awards that will be cash settled of 51,704 in 2021 and 45,646 in 2020.
(b) Reflects the target payout level.

The following table is a summary of the status of non-vested awards as of December 31, 2021 and changes during the year:

	Restricted Stock Units, Stock Grants, and Stock Units		Performance Shares	
	Shares	Weighted-Average Grant Date Fair Value	Shares (b)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2021	220,557	$ 77.93	260,004	$ 98.28
Granted	152,345	76.72	161,840	82.42
Vested	(115,099)	80.50	(136,070)	92.16
Forfeited (c)	(4,647)	80.11	(5,092)	95.07
Nonvested at December 31, 2021	253,156 (a)	79.37	280,682	92.16

Vested Awards Outstanding at December 31, 2021	88,706	136,070

(a) Includes 118,538 of awards that will be cash settled.
(b) The nonvested performance shares are reflected at target payout level.
(c) We account for forfeitures as they occur.

Share-based liabilities paid relating to restricted stock units were $4 million in 2021 and $6 million in 2020. This includes cash used to settle restricted stock units of $3 million in 2021 and $4 million in 2020. Restricted stock units that are cash settled are classified as liability awards. All performance shares are classified as equity awards.

Restricted Stock Units, Stock Grants, and Stock Units

Restricted stock units are granted to officers and key employees. Restricted stock units typically vest and settle in equal annual installments over a 4-year period after the grant date. Vesting is typically dependent upon continuous service during the vesting period; however, awards granted to retirement-eligible employees will vest upon the employee's retirement. Awardees typically elect to receive payment in either 100% stock, 100% cash, or 50% in cash and 50% in stock. Restricted stock unit awards typically include a dividend equivalent feature. This feature allows each award to accrue dividend rights equal to the dividends they would have received had they directly owned the stock. Interest on dividend rights compounds quarterly. If the award is forfeited the employee is not entitled to the dividends on those shares.

Compensation cost for restricted stock unit awards is based on the fair value of the award, with the fair value being the market price of our stock on the measurement date. Restricted stock unit awards that will be settled in cash are accounted for as liability awards, with compensation cost initially calculated on the date of grant using the Company's closing stock price, and remeasured at each balance sheet date. Restricted stock unit awards that will be settled in shares are accounted for as equity awards, with compensation cost calculated using the Company's closing stock price on the date of grant. Compensation cost is recognized over the requisite service period based on the fair value of the award.

Stock grants are issued to non-officer members of the Board of Directors. They may elect to receive the stock grant, or to defer receipt until a later date and receive stock units in lieu of the stock grant. The members of the Board of Directors who elect to defer may elect to receive payment in either 100% stock, 100% cash, or 50% in cash and 50% in stock. Each stock unit is convertible to one share of stock. The stock units accrue dividend rights, equal to the amount of dividends the Directors would have received had they directly owned stock equal to the number of vested restricted stock units or stock units from the date of grant to the date of payment, plus interest compounded quarterly. The dividends and interest are paid, based on the Director's election, in either stock, cash, or 50% in cash and 50% in stock.

Performance Share Awards

Performance share awards are granted to officers and key employees. The awards contain two separate performance criteria that affect the number of shares that may be received if after the end of a 3- year performance period the performance criteria are met. For the first criteria, the number of shares that will vest is based on non-financial performance metrics (i.e., the metric component). The other criteria is based upon Pinnacle West's total shareholder return ("TSR") in relation to the TSR of other companies in a specified utility index (i.e., the TSR component). The exact number of shares issued will vary from 0% to 200% of the target award. Shares received include dividend rights paid in stock equal to the amount of dividends that recipients would have received had they directly owned stock, equal to the number of vested performance shares from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited or if the performance criteria are not achieved, the employee is not entitled to the dividends on those shares.

Performance share awards are accounted for as equity awards, with compensation cost based on the fair value of the award on the grant date. Compensation cost relating to the metric component of the award is based on the Company's closing stock price on the date of grant, with compensation cost recognized over the requisite service period based on the number of shares expected to vest. Management evaluates the probability of meeting the metric component at each balance sheet date. If the metric component criteria are not ultimately achieved, no compensation cost is recognized relating to the metric component, and any previously recognized compensation cost is reversed. Compensation cost relating to the TSR component of the award is determined using a Monte Carlo simulation valuation model, with compensation cost recognized ratably over the requisite service period, regardless of the number of shares that actually vest.

16. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, emissions allowances, and interest rates. Risks associated with market volatility are managed by utilizing various physical and financial derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and natural gas. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms
(quantities, delivery points and delivery periods) and for which power does not flow are presented gross, which increases both revenues and fuel and purchased power costs in our Comparative Statements of Income, but does not impact our financial condition, net income or cash flows.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheets as an asset or liability and are measured at fair value. See Note 14 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 5). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

The following table shows the outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	Unit of Measure	December 31, 2021	December 31, 2020
Power	GWh	—	368
Gas	Billion cubic feet	155	205

Gains and Losses from Derivative Instruments

The following table provides information about APS's gains and losses from derivative instruments in designated cash flow accounting hedging relationships (dollars in thousands):

		Year Ended December 31,	
Commodity Contracts	Financial Statement Location	2021	2020
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	$ —	$ (763)

(a) During the years ended December 31, 2021 and 2020, we had no gains or losses reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.
(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that no amounts will be reclassified from accumulated OCI into income, as the delivery period for all derivative instruments in designated cash flow accounting hedging relationships have lapsed.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments (dollars in thousands):

		Year Ended December 31,	
Commodity Contracts	Financial Statement Location	2021	2020
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ 216,847	$ (3,178)

(a) Amounts are before the effect of PSA deferrals.

Derivative Instruments in the Comparative Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements and are reported gross on the Comparative Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The following tables provide information about the fair value of our risk management activities reported on a gross basis and the impacts of offsetting relating to transactions executed under master netting arrangements. While certain amounts may be eligible for offsetting under master netting arrangements, for FERC reporting purposes we do not offset on the balance sheet. These amounts relate to commodity contracts and are located in the assets and liabilities from derivative instrument lines of our Comparative Balance Sheets.

		Eligible for Offsetting		
As of December 31, 2021: (dollars in thousands)	Gross Recognized Derivatives (a)	Derivatives	Cash Collateral/Other (b)	Net Derivatives After Impacts of Offsetting
Current assets	$ 66,777	(3,346)	$ —	$ 63,431
Investments and other assets	48,302	$ (1,394)	—	46,908
Total assets	115,079	(4,740)	—	110,339
Current liabilities	(6,084)	3,346	—	(2,738)
Deferred credits and other	(1,394)	1,394	—	—
Total liabilities	(7,478)	4,740	—	(2,738)
Total	$ 107,601	$ —	$ —	$ 107,601

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting. We had total cash collateral received from counterparties of $1,635 and cash margin provided to counterparties of $50.

		Eligible for Offsetting		
As of December 31, 2020: (dollars in thousands)	Gross Recognized Derivatives (a)	Derivatives	Cash Collateral/Other (b)	Net Derivatives After Impacts of Offsetting
Current assets	$ 5,870	$ (2,939)	$ —	$ 2,931
Investments and other assets	3,150	(1,332)	—	1,818
Total assets	9,020	(4,271)	—	4,749
Current liabilities	(9,211)	2,939	—	(6,272)
Deferred credits and other	(12,394)	1,332	—	(11,062)
Total liabilities	(21,605)	4,271	—	(17,334)
Total	$ (12,585)	$ —	$ —	$ (12,585)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting. We had total cash collateral received from counterparties of $1,285.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of December 31, 2021, we have three counterparties for which our exposure represents approximately 38% of $110 million of risk management assets. This exposure relates to master agreements with counterparties and all three are rated as investment grade. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these counterparties could default, resulting in a material impact on earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

The following table provides information about our derivative instruments that have credit-risk-related contingent features (dollars in thousands):

	December 31, 2021
Aggregate fair value of derivative instruments in a net liability position	$ 7,478
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	2,658

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

We also have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $88 million if our debt credit ratings were to fall below investment grade.

17. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. Prior to April 1, 2021, the lease terms allowed APS the right to retain the assets through 2023 under one lease and 2033 under the other two leases. On April 1, 2021, APS executed an amended lease agreement with one of the VIE lessor trust entities relating to the lease agreement with the term ending in 2023. The amendment extends the lease term for this lease through 2033 and changes the lease payment. As a result of this amendment, APS will now retain the assets through 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2022 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

For regulatory reporting purposes, APS accounts for the three leases as operating leases for income statement and cash flow statement purposes, and for balance sheet purposes all three leases are classified as finance leases. See Note 10 for a discussion of leases.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $315 million beginning in 2022, and up to $501 million over the lease extension terms.

18. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds

We have investments in debt and equity securities held in Nuclear Decommissioning Trusts, Coal Reclamation Escrow Account, and an Active Union Employee Medical Account. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments
at their fair value on our Comparative Balance Sheets. See Note 14 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts — APS established external decommissioning trusts in accordance with NRC regulations to fund the future costs APS expects to incur to decommission Palo Verde. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities.

Coal Reclamation Escrow Account — APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because

Coal Reclamation Escrow Account — APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because of the ability of APS to recover coal reclamation costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

Active Union Employee Medical Account — APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2021 and 2020, APS was reimbursed $15 million and $14 million, respectively, for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below. On January 4, 2021, an additional $106 million of investments were transferred from APS other postretirement benefit trust assets into the active union employee medical account, see Note 9.

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	December 31, 2021					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 640,312	$ 47,570	$ 687,882		$ 451,387	$ —
Available for sale-fixed income securities	682,227	309,904	992,131	(a)	24,283	(4,063)
Other	(27,782)	936	(26,846)	(b)	—	—
Total	$ 1,294,757	$ 358,410	$ 1,653,167		$ 475,670	$ (4,063)

(a) As of December 31, 2021,the amortized cost basis of these available-for-sale investments is $972 million.
(b) Represents net pending securities sales and purchases.

	December 31, 2020					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 639,851	$ 37,337	$ 677,188		$ 421,666	$ —
Available for sale-fixed income securities	516,412	216,668	733,080	(a)	46,581	(398)
Other	(17,828)	504	(17,324)	(b)	—	—
Total	$ 1,138,435	$ 254,509	$ 1,392,944		$ 468,247	$ (398)

(a) As of December 31, 2020, the amortized cost basis of these available-for-sale investments is $687 million.
(b) Represents net pending securities sales and purchases.

The following table sets forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities (dollars in thousands):

	Year Ended December 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2021			
Realized gains	$ 134,610	$ 49	$ 134,659
Realized losses	(8,431)	(7)	(8,438)
Proceeds from the sale of securities (a)	1,457,305	263,661	1,720,966
2020			
Realized gains	12,194	176	12,370
Realized losses	(5,553)	(15)	(5,568)
Proceeds from the sale of securities (a)	675,035	144,484	819,519

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

Fixed Income Securities Contractual Maturities

The fair value of APS's fixed income securities, summarized by contractual maturities, at December 31, 2021, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 31,070	$ 36,852	$ 40,870	$ 108,792
1 year – 5 years	195,975	41,931	158,235	396,141
5 years – 10 years	155,202	1,775	21,846	178,823
Greater than 10 years	299,980	8,395	—	308,375
Total	$ 682,227	$ 88,953	$ 220,951	$ 992,131

19. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in APS's accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance at December 31, 2019	$ (34,948)		$ (574)		$ (35,522)
OCI (loss) before reclassifications	(9,568)		(18)		(9,586)
Amounts reclassified from accumulated other comprehensive loss	3,598	(a)	592	(b)	4,190
Balance at December 31, 2020	(40,918)		—		(40,918)
OCI (loss) before reclassifications	2,043		(18)		2,025

Amounts reclassified from accumulated other comprehensive loss	3,995	(a)	18	(b)	4,013
Balance at December 31, 2021	$ (34,880)		$ —		$ (34,880)

(a) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost (see Note 9).
(b) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA (see Note 16).

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(34,947,757)		(574,108)	(35,521,865)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				3,598,256		592,411	4,190,667		
3	Preceding Quarter/Year to Date Changes in Fair Value				(9,568,917)		(18,235)	(9,587,152)		
4	Total (lines 2 and 3)				(5,970,661)		574,176	(5,396,485)	568,028,218	562,631,733
5	Balance of Account 219 at End of Preceding Quarter/Year				(40,918,418)		68	(40,918,350)		
6	Balance of Account 219 at Beginning of Current Year				(40,918,418)		68	(40,918,350)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				3,995,037		18,235	4,013,272		
8	Current Quarter/Year to Date Changes in Fair Value				2,042,927		(18,235)	2,024,692		
9	Total (lines 7 and 8)				6,037,964			6,037,964	632,280,529	638,318,493
10	Balance of Account 219 at End of Current Quarter/Year				(34,880,454)		68	(34,880,386)		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	21,215,803,050	21,215,803,050					
4	Property Under Capital Leases	1,087,936,649	1,087,936,649					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,216,130,710	1,216,130,710					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	23,519,870,409	23,519,870,409					
9	Leased to Others							
10	Held for Future Use	10,206,915	10,206,915					
11	Construction Work in Progress	1,210,177,757	1,210,177,757					
12	Acquisition Adjustments	255,525,921	255,525,921					
13	Total Utility Plant (8 thru 12)	24,995,781,002	24,995,781,002					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	8,331,220,117	8,331,220,117					
15	Net Utility Plant (13 less 14)	16,664,560,885	16,664,560,885					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	7,277,027,654	7,277,027,654					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	977,625,298	977,625,298					
22	Total in Service (18 thru 21)	8,254,652,952	8,254,652,952					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							

29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	76,567,165	76,567,165					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	8,331,220,117	8,331,220,117					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	29,117,744	25,522,232		(a) 27,669,362	26,970,614
3	Nuclear Materials	81,555,373	20,095,759		(b) 23,832,199	77,818,933
4	Allowance for Funds Used during Construction	11,577,470	7,891,104		(c) 6,360,291	13,108,283
5	(Other Overhead Construction Costs, provide details in footnote)	2,387,032	2,331,858		(d) 2,797,865	1,921,025
6	SUBTOTAL (Total 2 thru 5)	124,637,619				119,818,855
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)		60,659,717		(e) 60,661,400	(1,683)
9	In Reactor (120.3)	250,852,003	60,738,731		(f) 72,428,563	239,162,171
10	SUBTOTAL (Total 8 & 9)	250,852,003				239,160,488
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	137,206,939		(68,266,216)	(g) 72,351,231	133,121,924
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	238,282,683				225,857,419
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer of Fuel in Process to Fuel in Stock

(b) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer of Fuel in Process to Fuel in Stock

(c) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer related to AFUDC cost from Fuel in Process to Fuel in Stock

(d) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer Use Tax Cost form Fuel in Process to Fuel in Stock

(e) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions

Transfer of Fuel in Stock to Fuel in Reactor

(f) Concept: NuclearFuelAssembliesInReactorOtherReductions

Amortization/Retirement of Fuel in Reactor

(g) Concept: AccumulatedProvisionForAmortizationOfNuclearFuelAssembliesOtherReductions

Amortization/Retirement of Fuel in Reactor

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	3,809,022					3,809,022
4	(303) Miscellaneous Intangible Plant	983,508,754	72,369,918	42,785,939		191,185	1,013,283,918
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	987,317,776	72,369,918	42,785,939		191,185	1,017,092,940
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	5,768,398		1,709		(339,419)	5,427,270
9	(311) Structures and Improvements	207,499,981	25,186,587	569,029		507,212	232,624,751
10	(312) Boiler Plant Equipment	1,501,209,095	55,633,260	16,461,763		151,686	1,540,532,278
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	223,810,228	4,152,894	1,211,510		(475,392)	226,276,220
13	(315) Accessory Electric Equipment	129,314,968	5,519,234	616,943		119,585	134,336,844
14	(316) Misc. Power Plant Equipment	107,104,800	(2,677,604)	314,547		533,014	104,645,663
15	(317) Asset Retirement Costs for Steam Production	53,732,721	24,498,716		(9,079,859)		69,151,578
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,228,440,191	112,313,087	19,175,501	(9,079,859)	496,686	2,312,994,604
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	4,417,789					4,417,789
19	(321) Structures and Improvements	893,359,656	15,988,828	1,934,435			907,414,049
20	(322) Reactor Plant Equipment	1,309,627,245	26,304,915	6,522,939			1,329,409,221
21	(323) Turbogenerator Units	453,633,310	8,841,729	945,192			461,529,847
22	(324) Accessory Electric Equipment	306,104,948	3,209,063	378,511			308,935,500
23	(325) Misc. Power Plant Equipment	258,919,322	(1,289,869)	7,818		(156,130)	257,465,505
24	(326) Asset Retirement Costs for Nuclear Production	(1,334,721)					(1,334,721)

25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,224,727,549	53,054,666	9,788,895		(156,130)	3,267,837,190
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights	15,768,919				339,419	16,108,338
38	(341) Structures and Improvements	246,158,662	17,922,498	1,336,742		15,405,706	278,150,124
39	(342) Fuel Holders, Products, and Accessories	63,190,168	3,691,288	443,820			66,437,636
40	(343) Prime Movers	1,040,762,125	55,694,479	25,904,920		15,464,778	1,086,016,462
41	(344) Generators	1,716,424,285	75,240,265	11,455,196		(18,139,964)	1,762,069,390
42	(345) Accessory Electric Equipment	284,573,645	19,496,000	944,547		2,706,406	305,831,504
43	(346) Misc. Power Plant Equipment	77,912,048	18,123,783	2,223,367		563,796	94,376,260
44	(347) Asset Retirement Costs for Other Production	29,870,536					29,870,536
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,474,660,388	190,168,313	42,308,592		16,340,141	3,638,860,250
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	8,927,828,128	355,536,066	71,272,988	(9,079,859)	16,680,697	9,219,692,044
47	3. Transmission Plant						
48	(350) Land and Land Rights	235,293,416	9,658,802	5,921,031			239,031,187
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	213,444,781	11,095,540	174,990		3,301,787	227,667,118
50	(353) Station Equipment	1,338,574,096	58,111,801	11,264,605		407,323	1,385,828,615
51	(354) Towers and Fixtures	189,342,642	2,539,563			(1)	191,882,204
52	(355) Poles and Fixtures	682,668,706	55,349,725	2,112,816		(356,169)	735,549,446
53	(356) Overhead Conductors and Devices	520,131,143	6,137,869	1,955,301		105,024	524,418,735
54	(357) Underground Conduit	51,623,537	(19,115,066)	86,073			32,422,398
55	(358) Underground Conductors and Devices	51,291,677	5,817,941				57,109,618
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,282,369,998	129,596,175	21,514,816		3,457,964	3,393,909,321
59	4. Distribution Plant						

60	(360) Land and Land Rights	77,560,082	7,061,921	310,149		(1,029,536)	83,282,318
61	(361) Structures and Improvements	101,116,705	11,397,513	342,961		2,673,974	114,845,231
62	(362) Station Equipment	755,725,532	86,260,003	4,634,650		(917,754)	836,433,131
63	(363) Energy Storage Equipment – Distribution	21,554	1,881,256				1,902,810
64	(364) Poles, Towers, and Fixtures	789,157,123	66,261,685	9,076,497		358,711	846,701,022
65	(365) Overhead Conductors and Devices	434,693,673	17,863,478	3,978,797		619,115	449,197,469
66	(366) Underground Conduit	786,071,293	26,336,029	1,161,679		11,152	811,256,795
67	(367) Underground Conductors and Devices	2,165,500,191	146,389,078	11,332,286	(2,815)	946,535	2,301,500,703
68	(368) Line Transformers	1,025,076,508	62,741,978	17,861,426		129,354	1,070,086,414
69	(369) Services	513,767,295	25,219,638	677,512		1,291,484	539,600,905
70	(370) Meters	324,234,927	17,217,918	11,160,439		71,013	330,363,419
71	(371) Installations on Customer Premises	48,517,518	1,730,837	1,948,845		(1,104,711)	47,194,799
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	84,138,414	3,989,697	3,093,530			85,034,581
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	7,105,580,815	474,351,031	65,578,771	(2,815)	3,049,337	7,517,399,597
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	23,117,705	(280)				23,117,425
87	(390) Structures and Improvements	350,843,086	18,388,724	2,625,128		(24,211,756)	342,394,926
88	(391) Office Furniture and Equipment	363,877,692	28,339,215	22,808,539		398,348	369,806,716
89	(392) Transportation Equipment	40,392,611	5,043,762	2,604,525			42,831,848
90	(393) Stores Equipment	629,963	(3,138)				626,825
91	(394) Tools, Shop and Garage Equipment	56,489,244	7,429,919	1,758,919		(1,445,678)	60,714,566
92	(395) Laboratory Equipment	941,626	442,815	232,014			1,152,427
93	(396) Power Operated Equipment	9,775,694	832,587	378,745			10,229,536
94	(397) Communication Equipment	365,853,018	33,433,738	2,417,791		850,367	397,719,332
95	(398) Miscellaneous Equipment	34,347,180	899,182	105			35,246,257

96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,246,267,819	94,806,524	32,825,766		(24,408,719)	1,283,839,858
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	1,246,267,819	94,806,524	32,825,766		(24,408,719)	1,283,839,858
100	TOTAL (Accounts 101 and 106)	21,549,364,536	1,126,659,715	233,978,280	(9,082,674)	(1,029,537)	22,431,933,760
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	21,549,364,536	1,126,659,715	233,978,280	(9,082,674)	(1,029,537)	22,431,933,760

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
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43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Roanoke Substation35th Ave. & Roanoke Ave., Phoenix, AZ	12/31/1991	12/31/2025	282,772
3	Paradise Substation15021 N. 33rd Place, Phoenix, AZ	10/31/2006	12/31/2025	401,193
4	Punkin Center Substation146 E. Purtill Trail, Tonto Basin, AZ	12/31/2014	12/31/2025	320,827
5	Buckeye to Elianto (SV4) Transmission LineTownship 010N 030W Sec 7; Buckeye, AZ	05/31/2008	12/31/2025	653,352
6	Citrus (WS4) SubstationParcel 502-40-267 /T01NR02W.S10/ 2.633 acres	05/01/2009	12/31/2025	427,534
7	Yavapai to WellfieldTownship 015N 001W; Yavapai, AZ	11/30/2016	01/01/2027	271,540
8	Sundance to Pinal CentralT06S:R07E:NW11 / 66.94 acres	02/01/2018	01/01/2028	1,328,057
9	Virginia (Willo) Substation40 E Virginia Ave., Phoenix, AZ	12/31/2019	12/31/2029	5,762,037
10	Other General Parcels (2)	12/31/1999	12/31/2025	111,576
11	Other Transmission Parcels (2)	12/31/1999	12/31/2025	92,023
12	Other Distribution Parcels (4)	12/31/1999	12/31/2025	556,004
13	0			
21	Other Property:			
22				
23				
24				
25				
26				
27				
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38				
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43				
44				
45				
46				
47	TOTAL			10,206,915

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Generation	
2	West Phoenix WC1 Dry Low NOX System	9,711,083
3	West Phoenix WC2 Dry Low NOX System	9,692,499
4	Redhawk Second Makeup Water Surge Pond	9,680,533
5	Motors / Pumps / Valves	7,713,782
6	Water Resources Management Well Health	6,615,678
7	Palo Verde CD-1218 - LP FW Heater 2C Replacement U2	6,266,873
8	Electrical Systems	5,660,225
9	Palo Verde License Renewal Operation Manual Replacement	5,583,599
10	Palo Verde Plant 2 Way Radio Replacement	5,104,398
11	Palo Verde Digital Upgrades	5,016,888
12	Clarifiers Life Extension T1	4,009,777
13	Palo Verde Spray Pond Concrete Replacement U3	3,767,859
14	Solar AZ Sun II	3,525,225
15	Four Corners Effluent Limitations Guidelines Plant Modifications	3,365,657
16	West Phoenix WC5 Steam Turbine L-0 Blade Replacement	2,952,295
17	Water Systems/Membranes	2,824,730
18	Palo Verde Spray Pond Concrete Replacement U1	2,548,454
19	Yucca New East Warehouse	2,468,366
20	Generation M&D Center	2,286,829
21	Palo Verde 10CRF50.69 Risk Informed	1,978,241
22	Palo Verde Normal Chiller Replacement U1	1,871,486
23	West Phoenix 5A Exhaust Manifold & Joint Replacement	1,865,063
24	Saguaro Firewater System	1,855,692
25	Four Corners Heat Trace System Replacement	1,730,137
26	Suppl Chain Opt & Reliab Effcy 4C	1,729,683
27	Palo Verde Fire Protection Piping	1,711,855
28	Palo Verde Railroad Spur and Crossing Replacement	1,662,064
29	Sundance Variable Bleed Valve Doors & Sprint Water Nozzles Replacement	1,615,326
30	Palo Verde Spray Pond Concrete Replacement U2	1,506,062

31	West Phoenix CC5A Rotor Replacement	1,470,502
32	Four Corners Low Volume Waste Pond Construction	1,372,735
33	Cholla Fly Ash/Bottom Ash Pond CCR Groundwater Mitigation	1,303,521
34	Palo Verde SP Chemical Addition	1,277,962
35	Palo Verde Best Estimate Loss of Coolant Accident Manual Replacement	1,236,058
36	Palo Verde Cyber Security Reassessment	1,193,199
37	West Phoenix 5A Major Outage Overhaul Additions & Ancillary Capital Costs	1,136,859
38	Four Corners CCR Groundwater Mitigation	1,130,375
39	Palo Verde Water Reclamation Facility Clarifiers Life Extension T1	456,971
40	Four Corners Supply Chain Optimization System Development	(83,121)
41	Other Generation Less Than $1 Million	(49,346,439)
42	Transmission	
43	Participant Op by APS	14,512,448
44	Cochise County Regional Improvements	3,159,120
45	DVA Facade Replacement	1,594,461
46	Pinal Central - Sundance 230kV Line Additions/Improvements	1,565,202
47	TGP Development Interconnection-Q3	1,450,177
48	Bacon: Methane Capture	1,402,719
49	Other Transmission Less Than $1 Million	(19,045,256)
50	Distribution	
51	100MW Battery Storage	133,242,021
52	Transformers	107,740,601
53	White Tanks Transformer	86,721,329
54	Western Service Center	71,624,848
55	Energy Delivery E&S	69,513,804
56	Residential Underground Distribution Lines Additions/Improvements	44,526,868
57	Underground Service-Line Extension -Non Residential	43,657,993
58	Benefit Load Difference	32,624,879
59	New Garfield Substation	25,538,233
60	ED Vehicle Overhead	22,013,135
61	Redhawk PV Solar	21,406,843
62	EV C&I L2 Chargers	13,708,781
63	Network Protectors	13,136,856
64	Incentive	13,025,008
65	Brannigan Substation	11,680,235
66	Supply Chain Mgmt Capital	10,073,757
67	Capital AMI Meters-Meter Ops	8,837,238
68	Capitalized Prop Tax	8,712,746

69	Encanto Substation 3rd Transformer	8,293,462
70	New Clarkdale Substation	7,544,627
71	New Cottonwood SC Con	7,068,954
72	ADMS RTUs Dual-Port	6,883,665
73	Buckeye Service Center Substation	6,795,805
74	Phoenix 23rd Street Micro Grid	5,905,516
75	Interstate EV DC Fast Charging	5,364,409
76	T&D Comm Plan FY21	4,253,401
77	EPRI Transformer Replacement	3,887,891
78	West Phoenix 230kV Single Point of	3,546,179
79	Preacher Canyon New Feeder	3,544,617
80	Capitalized Tools	3,228,298
81	Supervisory Controlled Switch Program	2,862,278
82	Wellfield Substation Transformer and Feeder Upgrade	2,571,366
83	ASSET-99	2,444,500
84	PTO Distributed to Capital	1,918,421
85	Midtown: Network Expansion	1,631,555
86	Kirkland Junction: Rebuild Line	1,451,801
87	Bunker Peak Substation	1,404,114
88	Phone Allocation	1,233,526
89	Grant: New Substation	1,206,968
90	Corporate E/S Overhead	1,092,809
91	SG2 SA2 Generator Rotor Wedge Repl	1,082,681
92	Storage Program	1,021,817
93	Other Distribution Less Than $1 Million	(148,582,002)
94	Transmission and Distribution	
95	AGT Reliability	14,787,366
96	Highway Line Relocation - Transmission And Distribution	10,571,268
97	Planned Overhead Line Replacements - Transmission and Distribution	8,745,160
98	Carol Springs Upgrade	1,314,150
99	General and Intangible	
100	Supply Chain Optimization & Reliability Efficiency	111,457,778
101	EMS Upgrade Project	46,430,986
102	TSMC Phase 1&2	37,858,113
103	Capitalized A&G	28,000,000
104	Application Sustainability Program	21,240,300
105	Twin Buttes: New Substation	18,668,484
106	Illuminate 2.5 - Advanced Apps and Breaker Control	14,182,603

107	Local Area Network Reliability	11,130,853
108	Unplanned/Emergency	10,974,509
109	Childs to Irving Tap 69kV Rebuild	10,827,425
110	Strategic Telecom Project	10,699,620
111	Payson to Pine Rebuild	10,499,495
112	DATA Analytics	9,244,311
113	CHQ Fire Alarms	7,920,303
114	White Spar - Wilhoit Rebuild 69kV	6,624,002
115	Runway Substation/Microsoft Phase 2	6,332,429
116	Wide Area Network Program	5,478,237
117	Utility Design Tool	5,016,228
118	Hohokam-Tempe 69kV Upgrade	4,619,444
119	Inventory - Wire inventory	4,475,732
120	Server Migrations	4,136,214
121	New in 2020	3,951,212
122	CRM Project 2020	3,757,432
123	Monitoring Systems Program	3,749,361
124	CHQ APU Replacement	3,543,006
125	2020 Rate Case Implementation	3,274,564
126	Identity management system	2,871,456
127	Cable Replacement	2,384,730
128	AGT Power Quality	2,248,310
129	Physical Security System Program	2,129,011
130	Client Applications Program	2,021,416
131	Stratus Sub/Microsoft Phase 2	1,981,656
132	Lease Buyouts on Equipment	1,757,228
133	MOD-30: IT TransOps Support	1,659,749
134	Standing Accrual	1,590,000
135	DVA Workplace of the Future Implementation	1,572,440
136	Facilities Run Maint-Exterior	1,476,421
137	WRF Clarifiers Life Extension 2020	1,142,838
138	Fire Warning Detection System Repla	1,015,779
139	Other General and Intangible Less Than $1 Million	(10,733,547)
43		1,210,177,757

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	6,935,687,334	6,935,687,334		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	536,310,780	536,310,780		
4	(403.1) Depreciation Expense for Asset Retirement Costs	5,881,163	5,881,163		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,906,960	1,906,960		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	544,098,903	544,098,903		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	[a](175,254,688)	(175,254,688)		
13	Cost of Removal	(59,890,828)	(59,890,828)		
14	Salvage (Credit)	47,741,682	47,741,682		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(187,403,834)	(187,403,834)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(15,354,749)	[b](15,354,749)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	7,277,027,654	7,277,027,654		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,095,450,294	1,095,450,294		
21	Nuclear Production	1,647,184,942	1,647,184,942		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,151,123,627	1,151,123,627		
25	Transmission	970,099,975	970,099,975		
26	Distribution	1,986,357,026	1,986,357,026		

27	Regional Transmission and Market Operation				
28	General	426,811,790	426,811,790		
29	TOTAL (Enter Total of lines 20 thru 28)	7,277,027,654	7,277,027,654		

FOOTNOTE DATA

(a) Concept: BookCostOfRetiredPlant		
FERC Page 219 Column (b), Line 12		175,254,688
Gain/(Loss) on Disposition of Assets		(581,723)
FERC Page 204-207 Column (d), Line 5		42,785,939
FERC Page 204-207 Column (d), Line 48		5,921,031
FERC Page 204-207 Column (d), Line 60		310,149
General Plant Retirements		8,573,319
Saguaro Steam Tank Sale		1,709
Early Termination of SW Licenses		1,713,168
FERC Page 204-207 Column (d), Line 104	$	233,978,280

(b) Concept: OtherAdjustmentsToAccumulatedDepreciation		
Palo Verde Decommissioning		(2,149,100)
Asset Retirement Obligation in Reg. Liability		(3,245,023)
Accelerated CIAC to Regulatory Assets		(332,041)
Navajo Regulatory Asset Amortization		(10,132,704)
West Phoneix COR - Amortization		(83,181)
Reserve Transfers-- Accounts 1110,1112, & 1220 & Other Entities		587,300
TOTAL	$	(15,354,749)

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
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41								
42	Total Cost of Account 123.1 $		Total					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	13,378,320	10,380,456	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6				
7	Production Plant (Estimated)	[a]163,822,801	[b]179,128,114	
8	Transmission Plant (Estimated)	[c]48,177,324	[d]52,770,104	
9	Distribution Plant (Estimated)	104,292,897	116,884,077	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[e](153,857)	[f]622,731	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	316,139,165	349,405,026	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	(1,394,570)	(270,325)	
17				
18				
19				
20	TOTAL Materials and Supplies	328,122,915	359,515,157	

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesProductionPlant

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

(b) Concept: PlantMaterialsAndOperatingSuppliesProductionPlant

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

(c) Concept: PlantMaterialsAndOperatingSuppliesTransmissionPlant

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

(d) Concept: PlantMaterialsAndOperatingSuppliesTransmissionPlant

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

(e) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to - Other. General Plant expenses for communication and garage equipment.

(f) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to - Other. General Plant expenses for communication and garage equipment.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	339,599.00		48,487.00		48,487.00		48,487.00		1,260,662.00		1,745,722.00	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									48,487.00		48,487.00	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	2,326.00										2,326.00	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Surrender to EPA	33,654.00										33,654.00	
23	Consent Decree												
24													

25													
26													
27													
28	Total	33,654.00										33,654.00	
29	Balance-End of Year	303,619.00		48,487.00		48,487.00		48,487.00		1,309,149.00		1,758,229.00	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	533.00		533.00		533.00		533.00		26,091.00		28,223.00	
37	Add: Withheld by EPA									1,066.00		1,066.00	
38	Deduct: Returned by EPA	533.00								533.00		1,066.00	
39	Cost of Sales												
40	Balance-End of Year			533.00		533.00		533.00		26,624.00		28,223.00	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	533.00	7.21							533.00	5.55	1,066.00	12.76
45	Gains		7.21								5.55		12.76
46	Losses												

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
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11						
12						
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14						
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21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
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43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
20	Total				
21	**Generation Studies**				
22	FACIL STDY,WA334372	7	143		143
23	FACIL STDY,WA352111	(6)	143		143
24	FACIL STDY,WA402793	4	143		143
25	FACIL STDY,WA402826	351	143		143
26	FACIL STDY,WA425876	(1,736)	143		143
27	FACIL STDY,WA431805	(521)	143		143
28	FACIL STDY,WA431809	(405)	143		143
29	FACIL STDY,WA431939	(901)	143		143
30	FACIL STDY,WA432055	33	143		143
31	FACIL STDY,WA432060	1,267	143		143
32	FACIL STDY,WA444215	(4,484)	143		143
33	FACIL STDY,WA444217	(4,350)	143		143
34	FACIL STDY,WA459370	(1,862)	143		143
35	FACIL STDY,WA459429	(2,138)	143		143
36	FACIL STDY,WA459497	(2,480)	143		143
37	FACIL STDY,WA459537	(433)	143		143
38	FACIL STDY,WA459895	2,239	143		143
39	FACIL STDY,WA459896	(2,902)	143	250,000	143
40	FACIL STDY,WA488493	6,421	143		143
41	FACIL STDY,WA517285	(1,732)	143		143
42	FACIL STDY,WA565967	13,435	143		143
43	FACIL STDY,WA602005	(201)	143		143
44	FACIL STDY,WA603220		143		143
45	SMG FACSTD,WA553147	737	143		143

46	SMG FACSTD,WA603218	(754)	143		143
47	SMG SISSTD,WA597916	877	143		143
48	SMG SISSTD,WA606497	5,944	143		143
49	SMG SISSTD,WA606843	314	143		143
50	SMG SISSTD,WA632339	173	143	(30,000)	143
51	SMG SISSTD,WA634317	1,958	143		143
52	SYSIMPTSTD,WA383670	(3,647)	143		143
53	SYSIMPTSTD,WA384886	(1,736)	143		143
54	SYSIMPTSTD,WA389046	19	143		143
55	SYSIMPTSTD,WA402547	(2,916)	143		143
56	SYSIMPTSTD,WA425874	(3,861)	143		143
57	SYSIMPTSTD,WA431719	(1,140)	143		143
58	SYSIMPTSTD,WA431807	8,482	143		143
59	SYSIMPTSTD,WA431944	(2,176)	143		143
60	SYSIMPTSTD,WA431968	(392)	143		143
61	SYSIMPTSTD,WA432059	(985)	143		143
62	SYSIMPTSTD,WA450463	(176)	143		143
63	SYSIMPTSTD,WA459432	(4,446)	143		143
64	SYSIMPTSTD,WA459433	(1)	143		143
65	SYSIMPTSTD,WA459505	7,797	143		143
66	SYSIMPTSTD,WA488489	(2,458)	143		143
67	SYSIMPTSTD,WA488579	(1,718)	143		143
68	SYSIMPTSTD,WA488582	(1,674)	143		143
69	SYSIMPTSTD,WA503830	(1,814)	143		143
70	SYSIMPTSTD,WA511475	2	143		143
71	SYSIMPTSTD,WA511477	(19)	143		143
72	SYSIMPTSTD,WA511627	(1,536)	143		143
73	SYSIMPTSTD,WA516333	(2,107)	143		143
74	SYSIMPTSTD,WA516518	(880)	143		143
75	SYSIMPTSTD,WA516741	5,481	143		143
76	SYSIMPTSTD,WA517253	(2,209)	143		143
77	SYSIMPTSTD,WA517446	7,812	143		143
78	SYSIMPTSTD,WA517447	7,041	143		143
79	SYSIMPTSTD,WA517448	6,917	143		143
80	SYSIMPTSTD,WA517449	(1,004)	143		143
81	SYSIMPTSTD,WA532273	(4)	143		143
82	SYSIMPTSTD,WA532276	(9)	143		143
83	SYSIMPTSTD,WA534568	144,000	143		143

84	SYSIMPTSTD,WA539190	(2,079)	143		143
85	SYSIMPTSTD,WA544770	848	143		143
86	SYSIMPTSTD,WA545423	827	143		143
87	SYSIMPTSTD,WA545425	(66)	143		143
88	SYSIMPTSTD,WA545531	(456)	143		143
89	SYSIMPTSTD,WA545722	(2,020)	143		143
90	SYSIMPTSTD,WA545728	(1,246)	143		143
91	SYSIMPTSTD,WA545757	(3,907)	143		143
92	SYSIMPTSTD,WA546276	(2,124)	143		143
93	SYSIMPTSTD,WA546547	(1,973)	143		143
94	SYSIMPTSTD,WA546548	293	143		143
95	SYSIMPTSTD,WA546664	(484)	143		143
96	SYSIMPTSTD,WA546667	(2,070)	143		143
97	SYSIMPTSTD,WA546767	(2,014)	143		143
98	SYSIMPTSTD,WA546770	47	143		143
99	SYSIMPTSTD,WA549226	33	143		143
100	SYSIMPTSTD,WA549419	34	143		143
101	SYSIMPTSTD,WA551476	(1,350)	143		143
102	SYSIMPTSTD,WA556959	18	143		143
103	SYSIMPTSTD,WA571836	(1,991)	143		143
104	SYSIMPTSTD,WA571837	(1,941)	143		143
105	SYSIMPTSTD,WA574357	3,024	143		143
106	SYSIMPTSTD,WA574418	(2,003)	143		143
107	SYSIMPTSTD,WA574485	(1,221)	143		143
108	SYSIMPTSTD,WA574522	(3,993)	143		143
109	SYSIMPTSTD,WA574523	(22)	143		143
110	SYSIMPTSTD,WA574525	1,650	143		143
111	SYSIMPTSTD,WA574690	11	143		143
112	SYSIMPTSTD,WA574721	(1,838)	143		143
113	SYSIMPTSTD,WA574748	9	143		143
114	SYSIMPTSTD,WA574749	(1,824)	143		143
115	SYSIMPTSTD,WA574775	1,654	143		143
116	SYSIMPTSTD,WA574782	4,817	143		143
117	SYSIMPTSTD,WA574791	9	143		143
118	SYSIMPTSTD,WA574816	(1,919)	143		143
119	SYSIMPTSTD,WA574818	1,784	143		143
120	SYSIMPTSTD,WA574838	3,734	143		143
121	SYSIMPTSTD,WA574842	(2,004)	143		143

122	SYSIMPTSTD,WA594256	(4,079)	143		143
123	SYSIMPTSTD,WA594257	(1,947)	143		143
124	SYSIMPTSTD,WA596156	76	143		143
125	SYSIMPTSTD,WA604606	(2,028)	143		143
126	SYSIMPTSTD,WA606554	(2,050)	143		143
127	SYSIMPTSTD,WA606616	(4,081)	143		143
128	SYSIMPTSTD,WA606634	1,756	143		143
129	SYSIMPTSTD,WA606635	20	143		143
130	SYSIMPTSTD,WA606636	190	143		143
131	SYSIMPTSTD,WA606637	(410)	143		143
132	SYSIMPTSTD,WA606835	(1,145)	143		143
133	SYSIMPTSTD,WA606863	(4,104)	143		143
134	SYSIMPTSTD,WA606864	(1,904)	143		143
135	SYSIMPTSTD,WA606865	2,798	143		143
136	SYSIMPTSTD,WA606866	25,635	143		143
137	SYSIMPTSTD,WA606867	4,142	143		143
138	SYSIMPTSTD,WA606868	(401)	143		143
139	SYSIMPTSTD,WA606869	(1,974)	143		143
140	SYSIMPTSTD,WA606871	(1,985)	143		143
141	SYSIMPTSTD,WA606872	(1,072)	143		143
142	SYSIMPTSTD,WA606891	(3,887)	143		143
143	SYSIMPTSTD,WA606892	(1,817)	143		143
144	SYSIMPTSTD,WA606894	1,849	143		143
145	SYSIMPTSTD,WA606909	(3,149)	143	250,000	143
146	SYSIMPTSTD,WA606911	(3,668)	143		143
147	SYSIMPTSTD,WA606912	1,687	143		143
148	SYSIMPTSTD,WA606914	(2,010)	143		143
149	SYSIMPTSTD,WA606915	(4,092)	143		143
150	SYSIMPTSTD,WA618021	12,169	143		143
151	SYSIMPTSTD,WA630428	(1,903)	143	(125,000)	143
152	SYSIMPTSTD,WA634246	(742)	143		143
153	SYSIMPTSTD,WA634254	(250)	143	160,605	143
154	SYSIMPTSTD,WA634257	(1,473)	143		143
155	SYSIMPTSTD,WA636515	(2,546)	143		143
156	SYSIMPTSTD,WA636518	(2,711)	143		143
157	SYSIMPTSTD,WA636520	(885)	143		143
158	SYSIMPTSTD,WA636581	(1,682)	143		143
159	SYSIMPTSTD,WA636699	(3,449)	143		143

160	SYSIMPTSTD,WA636707	(2,718)	143		143
161	SYSIMPTSTD,WA636708	(3,523)	143		143
162	SYSIMPTSTD,WA636711	(3,449)	143		143
163	SYSIMPTSTD,WA636716	(1,381)	143		143
164	SYSIMPTSTD,WA636722	(1,381)	143		143
165	SYSIMPTSTD,WA636731	(1,762)	143		143
166	SYSIMPTSTD,WA636732	(1,032)	143		143
167	SYSIMPTSTD,WA636749	(1,412)	143	(250,000)	143
168	SYSIMPTSTD,WA636750	(1,488)	143	(250,000)	143
169	SYSIMPTSTD,WA636751	(1,488)	143	(250,000)	143
170	SYSIMPTSTD,WA636755	(1,488)	143	(250,000)	143
171	SYSIMPTSTD,WA636759	539,429	143	(500,000)	143
172	SYSIMPTSTD,WA636760	(2,287)	143	982	143
173	SYSIMPTSTD,WA636761	(3,247)	143	(500,000)	143
174	SYSIMPTSTD,WA636830	(3,415)	143	(500,000)	143
175	SYSIMPTSTD,WA636842	(3,591)	143	(500,000)	143
176	SYSIMPTSTD,WA636844	(904)	143	(500,000)	143
177	SYSIMPTSTD,WA636863	(3,006)	143	(500,000)	143
178	SYSIMPTSTD,WA636864	(3,006)	143	(500,000)	143
179	SYSIMPTSTD,WA636865	(6,270)	143	(500,000)	143
180	SYSIMPTSTD,WA636872	(3,218)	143	(500,000)	143
181	SYSIMPTSTD,WA636873	(3,909)	143	(500,000)	143
182	SYSIMPTSTD,WA636874	(3,958)	143	(500,000)	143
183	SYSIMPTSTD,WA636883	(1,710)	143	(250,000)	143
184	SYSIMPTSTD,WA636904	(2,809)	143	(500,000)	143
185	SYSIMPTSTD,WA636920	(3,594)	143	(500,000)	143
186	SYSIMPTSTD,WA636929	(3,174)	143	(500,000)	143
187	SYSIMPTSTD,WA636934	(3,371)	143	(500,000)	143
188	SYSIMPTSTD,WA636935	(1,708)	143	(250,000)	143
189	SYSIMPTSTD,WA636938	(3,518)	143	(500,000)	143
190	SYSIMPTSTD,WA637059	(1,933)	143	(250,000)	143
191	SYSIMPTSTD,WA637061	(1,393)	143	(250,000)	143
192	SYSIMPTSTD,WA637064	(3,317)	143	(500,000)	143
193	SYSIMPTSTD,WA637065	(2,685)	143	(500,000)	143
194	SYSIMPTSTD,WA637066	(1,968)	143	(500,000)	143
195	SYSIMPTSTD,WA637067	(1,609)	143	(250,000)	143
196	SYSIMPTSTD,WA637068	(3,069)	143	(500,000)	143
197	SYSIMPTSTD,WA637071	68	143		143

198	SYSIMPTSTD,WA637538	345,193	143	(320,000)	143
39	Total	919,522		(12,063,413)	
40	Grand Total	919,522		(12,063,413)	

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred Compensation Amortize through 2036	36,195,264		131,174,224,253	2,198,689	33,996,575
2	Capital Contribution on Phoenix-Mead Transmission U-1345-90-269 Amortize through 2050	9,712,196		108	332,041	9,380,155
3	Income Taxes - ACUDC Equity E-01345A-03-0437 Amortize through 2051	165,945,450	13,616,151	283,410.1	7,168,308	172,393,293
4	AG-1 Deferral E-01345A-11-0224 Amortize through 2021	2,716,073		407.3	2,716,073	
5	Deferred Fuel and Purchased Power E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2022	175,834,582	256,870,753	411.8,555,547,502,411.9	44,557,172	388,148,163
6	Deferred Fuel and Purchased Power - Mark-to-Market E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2024	12,585,132		547,555	12,585,132	
7	Deferred Fuel and Purchased Power - Interest E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2022	4,354,745	934,428	1823	4,953,840	335,333
8	Navajo Coal Reclamation E-01345A-08-0172 Amortize through 2026	18,067,134		501	1,227,000	16,840,134
9	Pension and Other Postretirement Benefits E-01345A-08-0172	469,952,578	49,473,482	128, 228.3, 926	9,675,148	509,750,912
10	Income Taxes - Change in Rates Amortize through 2051	1,001,630	859	283,410.1	1,127,375	(124,886)
11	Income Taxes - Medicare Subsidy Amortize through 2024	4,939,207		283,410.1	1,235,292	3,703,915
12	Income Taxes - Investment Tax Credit Basis Adjustment E-01345A-16-0036 Amortize through 2056	25,404,103	492,945	283,410.1	1,129,271	24,767,777
13	Property Tax Deferral E-01345A-11-0224 Amortize thorugh 2027	58,195,832		408	8,569,368	49,626,464
14	Lost Fixed Cost Recovery E-01345A-11-0224 Amortize through 2022	41,807,409	53,778,885	400	31,697,256	63,889,038
15	Retired Power Plant Costs Amortize through 2033	142,395,417		403, 404, 407	27,554,765	114,840,652
16	Four Corners Cost Deferral Amortize through 2024	32,151,685		407	8,076,583	24,075,102
17	SCR Deferral E-01345A-16-0036 though 2031	81,306,873	25,143,271	407	678,913	105,771,231
18	TCA Balancing account E-01345A-16-0036 Amortize through 2023		8,105,258	400	(a) 4,271,466	3,833,792
19	Deficient Deferred Income Taxes Tax Cuts & Jobs Act-ACC Portion to be amortized through 2046	2,885,691		283/410.1	(a) 113,533	2,772,158
20	Deficient Deferred Income Taxes Tax Cuts & Jobs Act-FERC Amortize through 2058	9,062,181		283/410.1	534,202	8,527,979
21	Tax Expense Adjustor Mechanism Amortize through 2031	6,225,773	441,855	400	166,731	6,500,897
22	Ocotillo Deferral E-01345A-16-0036 though 2031	95,722,739	52,719,971	407	792,271	147,650,439
23	Demand Side Management Amortize through 2022	7,268,131	919,316	908	7,268,131	919,316

24	Customer bill relief deferral E-00000A-19-128	1,100,000	700,000			1,800,000
25	Active Union Medical Trust E-01345A-19-0236		1,175,089			1,175,089
44	TOTAL	1,404,829,825	464,372,263		178,628,560	1,690,573,528

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Deficient Deferred Income Taxes – Tax Cuts and Jobs Act-ACC: Amount Amortized to Income Tax Expense Account 410.1: $85,179

(b) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Deficient Deferred Income Taxes – Tax Cuts and Jobs Act-FERC: Amount Amortized to Income Tax Expense Account 410.1: $401,241

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Information Systems Leases and Maintenance	15,173,542	16,070,009	165	18,090,344	13,153,207
2	Prepaid Water Supply Agreements through 2050	6,169,970		165	219,632	5,950,338
3	Four Corners NEPA through 2041	4,517,820		506	207,692	4,310,128
4	Unamortized Arrangement Fees through 2026	1,253,605	3,734,452	431,525	1,764,998	3,223,059
5	Transmission Right of Way		1,700,000			1,700,000
6	Rapid Response Center Equipment through 2047	710,971		232	27,269	683,702
7	Transmission Debits through 2026	1,821,570		565	1,271,830	549,740
8	Long Term Prepaid Insurance	3,422	245,341	165	248,763	
9	Debt Shelf Registration	2,400	171,028	181,428,431	173,428	
10	Minor Items	825,811	217,947	various	954,802	88,956
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	30,479,111				29,659,130

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Regulated Liabilities - Other	190,455,876	208,039,579
3			
4			
5	Operating Lease Liabilities	107,414,245	204,377,923
6			
7			
8			
9	Regulated Liabilities - Asset Retirement Obligation	125,145,929	151,949,611
10	TCJA Excess Deferred Taxes	(a) 322,045,706	(b) 309,708,172
11	Pension and Other Post Retirement Liabilities	40,167,964	37,813,585
12			
7	Other	167,010,535	169,727,854
8	TOTAL Electric (Enter Total of lines 2 thru 7)	952,240,255	1,081,616,724
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
16.0	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	952,240,255	1,081,616,724

Notes

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

TCJA Excess Deferred Taxes - FERC Jurisdiction		60,699,431
TCJA Excess Deferred Taxes - ACC Jurisdiction		261,346,275
Total	$	322,045,706

(b) Concept: AccumulatedDeferredIncomeTaxes

TCJA Excess Deferred Taxes - FERC Jurisdiction		58,745,648
TCJA Excess Deferred Taxes - ACC Jurisdiction		250,962,524
Total	$	309,708,172

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock	100,000,000	2.50		71,264,947	178,162,368				
7	Total	100,000,000			71,264,947	178,162,368				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-03-16	Year/Period of Report End of: 2021/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	1,505,626
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	1,505,626
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	16,894,739
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
15.2	[a] Transfer of Contract from Pinnacle West Marketing & Trading LLC	
15.3	Beginning Balance Amount: $12,323,739	
15.4	Credit	
15.5	Debit	
15.6	Balance at End of Year: $12,323,739	
15.7	[b] El Dorado transfer of Aegis software to APS	
15.8	Balance at Beginning of Year: $4,571,000	
15.9	Balance at End of Year: $4,571,000	
16	Ending Balance Amount	16,894,739
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	18,400,365
19.1	Increases (Decreases) in Other Paid-In Capital	

20	Ending Balance Amount	18,400,365
40	Total	18,400,365

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-03-16	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherPaidInCapitalDescription

Pinnacle West Marketing & Trading LLC is a subsidiary of Pinnacle West Capital Corporation, parent to Arizona Public Service Company

(b) Concept: OtherPaidInCapitalDescription

El Dorado is a subsidiary of Pinnacle West Capital Corporation, parent to Arizona Public Service Company.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense	37,461,284
2	Shelf Registration	50,368
22	TOTAL	37,511,652

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Palo Verde Project) 2009 Series A	221	35,975,000		576,013			06/26/2009	05/01/2029	06/26/2009	05/01/2029	35,975,000	93,491
3	Subtotal		35,975,000		576,013							35,975,000	93,491
4	Reacquired Bonds (Account 222)												
5													
6													
7													
8	Subtotal												
9	Advances from Associated Companies (Account 223)												
10													
11													
12													
13	Subtotal												
14	Other Long Term Debt (Account 224)												
15	5.625% Unsecured Senior Note	224	200,000,000		4,337,339	2,049,339	2,288,000	05/07/2003	05/15/2033	05/07/2003	05/15/2033	200,000,000	11,250,000
16	5.500% Unsecured Senior Note	224	250,000,000		4,510,192	2,362,692	2,147,500	08/22/2005	09/01/2035	08/22/2005	09/01/2035	250,000,000	13,750,000
17	6.875% Unsecured Senior Note	224	150,000,000		1,560,269	1,333,769	226,500	08/03/2006	08/01/2036	08/03/2006	08/01/2036	150,000,000	10,312,500
18	5.05% Unsecured Senior Note	224	300,000,000		5,118,550	3,096,550	2,022,000	08/25/2011	09/01/2041	08/25/2011	09/01/2041	300,000,000	15,150,000

19	4.50% Unsecured Senior Note	224	325,000,000		6,395,873	3,321,373	3,074,500	01/13/2012	04/01/2042	01/13/2012	04/01/2042	325,000,000	14,625,000
20	4.50% Unsecured Senior Note	224	100,000,000		(4,033,360)	1,148,640	(5,182,000)	01/13/2012	04/01/2042	01/13/2012	04/01/2042	100,000,000	4,500,000
21	4.70% Unsecured Senior Note	224	250,000,000		3,501,050	2,501,050	1,000,000	01/10/2014	01/15/2044	01/10/2014	01/15/2044	250,000,000	11,750,000
22	3.35% Unsecured Senior Note	224	250,000,000		2,310,950	2,080,950	230,000	06/18/2014	06/15/2024	06/18/2014	06/15/2024	250,000,000	8,375,000
23	3.15% Unsecured Senior Note	224	300,000,000		3,962,360	2,384,360	1,578,000	05/19/2015	05/15/2025	05/19/2015	05/15/2025	300,000,000	9,450,000
24	4.35% Unsecured Senior Note	224	250,000,000		2,978,924	2,518,924	460,000	11/06/2015	11/15/2045	11/06/2015	11/15/2045	250,000,000	10,875,000
25	3.75% Unsecured Senior Note	224	350,000,000		4,696,495	3,691,995	1,004,500	05/06/2016	05/15/2046	05/06/2016	05/15/2046	350,000,000	13,125,000
26	2.55% Unsecured Senior Note	224	250,000,000		3,276,425	2,118,925	1,157,500	09/20/2016	09/15/2026	09/20/2016	09/15/2026	250,000,000	6,375,000
27	4.35% Unsecured Senior Note	224	250,000,000		(1,193,525)	2,628,975	(3,822,500)	03/21/2017	11/15/2045	03/21/2017	11/15/2045	250,000,000	10,875,000
28	2.95% Unsecured Senior Note	224	300,000,000		2,766,770	2,559,770	207,000	09/11/2017	09/15/2027	09/11/2017	09/15/2027	300,000,000	8,850,000
29	4.20% Unsecured Senior Note	224	300,000,000		5,340,850	3,210,850	2,130,000	08/09/2018	08/15/2048	08/09/2018	08/15/2048	300,000,000	12,600,000
30	4.25% Unsecured Senior Note	224	300,000,000		3,317,360	3,266,360	51,000	02/28/2019	03/01/2049	02/28/2019	03/01/2049	300,000,000	12,750,000
31	2.60% Unsecured Senior Note	224	405,000,000		(3,631,562)	3,794,788	(7,426,350)	08/19/2019	08/15/2029	08/19/2019	08/15/2029	300,000,000	10,530,000
32	3.50% Unsecured Senior Note	224	300,000,000		3,481,940	3,313,940	168,000	11/20/2019	12/01/2049	11/20/2019	12/01/2049	405,000,000	10,500,000
33	3.35% Unsecured Senior Note	224	600,000,000		9,495,471	6,681,471	2,814,000	05/22/2020	05/15/1950	05/22/2020	05/15/1950	600,000,000	20,100,000
34	2.65% Unsecured Senior Note	224	400,000,000		5,947,917	4,383,917	1,564,000	09/11/2020	09/15/1950	09/11/2020	09/15/1950	400,000,000	10,600,000
35	2.20% Unsecured Senior Note	224	450,000,000		4,044,010	3,967,510	76,500	08/16/2021	12/15/2031	08/16/2021	12/15/2031	450,000,000	3,725,806
36	COLI LOANS (Option II Benefits)		30,576,738									[a]30,576,738	
37	Subtotal		6,310,576,738		68,184,298	62,416,148	5,768,150					6,310,576,738	230,068,306
33	TOTAL		6,346,551,738									6,346,551,738	[a]230,161,797

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherLongTermDebt

The change in the loan balance for the Coli Loan is as follows:

Total outstanding balance @ 12/31/20	$	32,533,545
2021 death repayments		(3,171,962)
2021 net premiums		435,145
2021 net interest		780,010
Balance outstanding @ 12/31/20	$	30,576,738

(b) Concept: InterestExpenseOnLongTermDebtIssued

The difference between the total column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies is as follows:

Total interest in 427 and 430	$	231,351,615
Less:		
Navajo ROW – Past Obligation		(1,185,388)
Letter of Credit Fees		(3,929)
Other		(501)
Total long term interest		230,161,797

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	632,280,529
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	91,836,122
6	Tax Gain/Loss on Sale of Business Property	(28,521,655)
7	Other Taxable Income Not Reported on Books	6,403,870
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	708,945,857
11	Income Tax Per Books	126,087,684
12	Pension and Other Post-Retirement Benefits	(95,831,752)
13	Other Deductions Recorded on Books Not Deducted for Return (see footn)	[a]251,324,791
14	Income Recorded on Books Not Included in Return	
15	Book Gain/Loss on Sale of Business Property	(2,999,641)
16	Cash Surrender Value	(780,010)
17	Other Income Recorded on Books Not Included in Return	(2,336,950)
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	(678,907,116)
21	Expenditures Capitalized for Book Not Tax	(322,696,120)
22	Other Deductions on Return Not Charged Against Book Income (see footn)	[b](606,021,095)
27	Federal Tax Net Income	78,784,514
28	Show Computation of Tax:	
29	$78,784,514 * 21%	16,544,748
30	Tax Attributes Utilized	(7,530,252)
31	Net Current Year Federal Tax Expense	9,014,496
32	Other (includes 2020 Return-to-Provision)	(5,811,869)
33	Net Federal Tax Expense per Income Statement	3,202,627

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Other Deductions Recorded on Books Not Deducted for Return consists of the following:

Book Accrued Expenses - End of Year		239,057,153
Regulatory Accounting Adjustments		5,878,236
Other		6,389,402
Total	$	251,324,791

(b) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Other Deductions on Return Not Charged Against Book Income consists of the following:

Book Accrued Expenses - Beginning of Year		(249,917,741)
Pension and Other Post Retirement Benefits		(77,374,784)
Regulatory Accounting Adjustments		(266,565,959)
Contributions to Qualified Decommissioning Fund		(2,281,000)
State Taxes		(26,542)
Other		(9,855,069)
Total	$	(606,021,095)

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1					0	0	0	0	0		0	0	0	0	0
2	**Subtotal Federal Tax**				0	0									
3	**Subtotal State Tax**				0	0									
4	**Subtotal Local Tax**				0	0									
5	**Subtotal Other Tax**				0	0									
6	Real and Personal Property	Property Tax	Arizona	2021	97,088,261	0	206,416,847	200,570,602	0	102,934,506	0	214,308,429	0	0	(7,891,582)
7	Real and Personal Property	Property Tax	California	2021	0	0	25,531	25,534	0	(3)	0	25,531	0	0	0
8	Real and Personal Property	Property Tax	Nevada	2021	0	0	87,195	87,195	0		0	87,195	0	0	0
9	Real and Personal Property	Property Tax	New Mexico	2021	9,186,352	0	19,573,280	19,023,757	0	9,735,875	0	19,573,280	0	0	0
10	**Subtotal Property Tax**				106,274,613	0	226,102,853	219,707,088		112,670,378		233,994,435			(7,891,582)
11	**Subtotal Real Estate Tax**				0	0									
12	Unemployment-Federal	Unemployment Tax		2021	0	0	277,448	277,448	0		0	0	0	0	277,448
13	Unemployment	Unemployment Tax	Arizona	2021	0	0	249,308	249,308	0		0	0	0	0	249,308
14	Unemployment	Unemployment Tax	California	2021	0	0	0	0	0		0	0	0	0	0
15	Unemployment	Unemployment Tax	New Mexico	2021	0	0	30,318	30,318	0		0	0	0	0	30,318
16	**Subtotal Unemployment Tax**				0	0	557,074	557,074							557,074
17	State and City Sales	Sales And Use Tax	Arizona	2021	17,697,243	0	276,252,912	275,877,633	0	18,072,522	0	0	0	0	276,252,912
18	State and City Use	Sales And Use Tax	Arizona	2021	113,960	0	26,565,448	24,591,801	0	2,087,607	0	0	0	0	26,565,448

19	State and City Tax Reserve	Sales And Use Tax	Arizona	2021	5,847,957	0	182,777	0	0	6,030,734	0	38,664	0	0	144,113
20	Sales Tax	Sales And Use Tax	New Mexico	2021	0	0	732	653	0	79	0	0	0	0	732
21	Use Tax	Sales And Use Tax	New Mexico	2021	0	0	1,918	2,258	0	(340)	0	0	0	0	1,918
22	Sales Tax-Unbilled Revenue	Sales And Use Tax	Arizona	2021	12,756,289	0	0	0	552,109	13,308,398	0	0	0	0	552,109
23	**Subtotal Sales And Use Tax**				36,415,449	0	303,003,787	300,472,345	552,109	39,499,000		38,664			303,517,232
24	Federal Income Tax	Income Tax			32,126,758	0	3,202,628.00	19,738,917.00	0	26,300,011	10,709,542.00	(3,014,453.00)			6,217,081.00
25	Arizona Income Tax	Income Tax	Arizona		1,271	0	(1,271)	0	0			(1,533,343)			1,532,072
26	California Income Tax	Income Tax	California		0	0	3,233	800.00	0		(2,433)	272			2,961
27	New Mexico Income Tax	Income Tax	New Mexico		8,408	0	(13,453)	43,392.00	0		48,437	(22,064)			8,611
28	**Subtotal Income Tax**				32,136,437	0	3,191,137	19,783,109		26,300,011	10,755,546	(4,569,588)			7,760,725
29	Heavy Use Vehicle Use-Federal	Excise Tax		2021	(58,947)	0	94,032	96,664	0	(61,579)	0	0	0	0	94,032
30	**Subtotal Excise Tax**				(58,947)	0	94,032	96,664		(61,579)					94,032
31	Fuel Tax-Federal	Fuel Tax		2021	(83,165)	0	0	13,036	0	(96,201)	0	0	0	0	0
32	**Subtotal Fuel Tax**				(83,165)	0		13,036		(96,201)					
33	FICA	Federal Insurance Tax		2021	0	0	54,131,657	54,131,657	0		0	27,595,813	0	0	26,535,844
34	**Subtotal Federal Insurance Tax**				0	0	54,131,657	54,131,657				27,595,813			26,535,844
35	**Subtotal Franchise Tax**				0	0									
36	**Subtotal Miscellaneous Other Tax**				0	0									
37	**Subtotal Other Federal Tax**				0	0	0	0	0		0	0	0	0	0
38	**Subtotal Other State Tax**				0	0									
39	**Subtotal Other Property Tax**				0	0									
40	**Subtotal Other Use Tax**				0	0									
41	**Subtotal Other Advalorem Tax**				0	0									
42	**Subtotal Other License And Fees Tax**				0	0									
43	**Subtotal Payroll Tax**				0	0									
44	**Subtotal Advalorem Tax**				0	0									
45	**Subtotal Other Allocated Tax**				0	0									
46	**Subtotal Severance Tax**				0	0									
47	**Subtotal Penalty Tax**				0	0									

48	**Subtotal Other Taxes And Fees**				0	0									
40	TOTAL				174,684,387	0	587,080,540	594,760,973	552,109	178,311,609	10,755,546	257,059,324			330,573,325

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2		191,371,520	255	3,711,925	420	8,513,538		186,569,907	21.91	
3	3%									
4	4%									
5	7%									
6	10%									
8	TOTAL Electric (Enter Total of lines 2 thru 7)	191,371,520		3,711,925		8,513,538		186,569,907		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	191,371,520						186,569,907		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredInvestmentTaxCredits

No amount is associated with transmission investments.

(b) Concept: AccumulatedDeferredInvestmentTaxCredits

No amount is associated with transmission investments.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Coal Reclamation	170,097,242			4,518,846	174,616,088
2	Interconnection Studies	22,579,953	143	115,174,492	139,699,661	47,105,122
3	Coal Community Transition through 2038	25,200,000	427	2,850,000	900,000	23,250,000
4	SCE Right of Way	17,881,083	232, 567	436,172		17,444,911
5	Construction Advances		107	9,547,419	23,252,439	13,705,020
6	Retention	174,869			12,915,709	13,090,578
7	Carbon Allowances		509, 242	1,544,697	6,805,260	5,260,563
8	License Fees through 2024	6,039,591	930	7,549,061	6,113,840	4,604,370
9	Legal Reserves	3,194,999	131,426.3	126,459	505,951	3,574,491
10	Deferred Compensation	1,452,968	182	649,894		803,074
11	Staples Rebate through 2023	90,000	920	468,125	1,139,171	761,046
12	Imperial Irrigation Prepaid O&M	300,000				300,000
47	TOTAL	247,010,705		138,346,319	195,850,877	304,515,263

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	2,457,574,784	380,776,092	290,740,242							2,547,610,634
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	2,457,574,784	380,776,092	290,740,242			—		—		2,547,610,634
6	UTP recorded in ADIT for FERC	19,940,683		1,154,109							18,786,574
9	TOTAL Account 282 (Total of Lines 5 thru 8)	2,477,515,467	380,776,092	291,894,351			—		—		2,566,397,208
10	Classification of TOTAL										
11	Federal Income Tax	2,083,123,798	297,138,227	253,463,215							2,126,798,810
12	State Income Tax	394,391,668	83,637,866	38,431,137							439,598,397
13	Local Income Tax										

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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Reg Assets - Mark to Market	47,673,124	50,332,212	1,972,216							96,033,120
4	Reg Assets - Pension and Other	116,219,274	10,267,994	476,843							126,010,425
5	Reg Assets - Other	(a) 185,681,812	34,870,449	22,883,280							(b) 197,668,981
6	ROU Asset for Leases	107,414,248	118,832,285	21,868,610							204,377,923
7	Pension and Other Postretirement Assets	122,579,900	25,900,540	15,711,226							132,769,214
8	Other	50,670,030	51,332,610	2,138,122							99,864,518
9	TOTAL Electric (Total of lines 3 thru 8)	630,238,388	291,536,090	65,050,297							856,724,181
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	630,238,388	291,536,090	65,050,297							856,724,181
20	Classification of TOTAL										
21	Federal Income Tax	524,283,698	238,387,244	54,793,949							707,876,993
22	State Income Tax	105,954,690	53,148,846	10,256,348							148,847,188
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Included in the total are the following amounts:	
Reg Asset - TCJA Excess Deferred Taxes - ACC Jurisdiction	713,632
Reg Asset - TCJA Excess Deferred Taxes - FERC Jurisdiction	2,241,078

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Included in the total are the following amounts:	
Reg Asset - TCJA Excess Deferred Taxes - ACC Jurisdiction	685,278
Reg Asset - TCJA Excess Deferred Taxes - FERC Jurisdiction	2,108,116

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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Asset Retirement Obligations FERC Order# 552 Amortize through 2057	506,049,047			108,633,845	614,682,892
2	Spent Nuclear Fuel Storage E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2027	50,989,089	518	6,561,910	855,242	45,282,421
3	Income Taxes - Unamortized Investment Tax Credit E-01345A-05-0816, -0826, -0827 Amortize through 2056	50,879,203	190	2,263,933	985,890	49,601,160
4	Sundance Maintenance E-01345A-05-0816, -0826, -0827 Amortize through 2031	14,496,750	553	2,432,831	1,733,115	13,797,034
5	Income Tax - Change in Rates Amortize through 2047	70,393,883	190/410.1	2,840,639		67,553,244
6	Renewable Energy Standard E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2022	39,544,681	549	75,015,588	74,111,032	38,640,125
7	Demand Side Management E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2022	10,818,585	908	57,450,284	52,048,905	5,417,206
8	Other Postretirement Benefits E-01345A-08-0172	387,293,216	926.1	47,382,139	34,904,180	374,815,257
9	Unrecovered removal costs Cholla	14,308,627			920,552	15,229,179
10	Unrecovered removal costs Saguaro	10,835,337			464,620	11,299,957
11	Property Tax Deferral E01345A-11-0224 though 2024	13,855,714	408.1	389,254	6,725,683	20,192,143
12	Four Corners Coal Reclamation E-013454A-05-0816, -0826, -0827 Amortize through 2038	54,895,489	501	4,702,734	5,198,572	55,391,327
13	Deferred Gain on Sale of Property E-01345A-09-0357 Amortize through 2022	3,967,198	421.1	2,422,788	307,224	1,851,634
14	Excess Deferred Income Taxes Tax Cuts & Jobs Act-ACC Portion to be amortized through 2046	1,056,798,525	190/411.1	[a]41,577,957		1,015,220,568
15	Excess Deferred Income Taxes Tax Cuts & Jobs Act-FERC Amortize through 2058	245,448,568	190/411.1	[b]7,804,362		237,644,206
16	Tax Expense Adjustor Mechanism E-01345A-18-0003	7,089,149	400	7,089,149	4,835,048	4,835,048
17	EIS Balancing Account Amortize through 2023	486,439	400	366,435	61,607	181,611
18	TCA Balancing account E-01345A-16-0036 Amortize through 2022	7,574,196	400	7,574,196		0
19	FERC Transmission True up Amortize through 2023	9,605,266	400	6,986,503	31,684,891	34,303,654
20	Active Union Medical Trust E-01345A-19-0236	6,057,265	128	7,232,354	1,175,089	0
21	Deferred Fuel and Purchased Power - Mark-to-Market E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2024				107,601,703	107,601,703
41	TOTAL	2,561,386,227		280,093,056	432,247,198	2,713,540,369

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FOOTNOTE DATA

(a) Concept: DecreaseInOtherRegulatoryLiabilities

Excess Deferred Income Taxes – Tax Cuts & Jobs Act-ACC: Amount Amortized to Income Tax Expense Account 411.1: $31,194,206

(b) Concept: DecreaseInOtherRegulatoryLiabilities

Excess Deferred Income Taxes – Tax Cuts & Jobs Act-FERC: Amount Amortized to Income Tax Expense Account 411.1: $5,850,579

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Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,913,324,211	1,929,176,208	14,223,711	14,747,876	1,177,343	1,150,194
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,390,441,902	[a]1,297,688,464	12,729,685	[b]12,148,521	135,503	133,874
5	Large (or Ind.) (See Instr. 4)	[a]176,211,405	[a]168,994,809	2,165,830	[b]2,212,432	3,019	3,231
6	(444) Public Street and Highway Lighting	20,153,935	19,293,027	107,124	122,752	1,266	1,266
7	(445) Other Sales to Public Authorities	132,468	121,141	1,886	1,714	135	138
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	3,500,263,921	3,415,273,649	29,228,236	29,233,295	1,317,266	1,288,703
11	(447) Sales for Resale	214,111,295	102,794,019	3,850,839	3,088,308	45	49
12	TOTAL Sales of Electricity	3,714,375,216	3,518,067,668	33,079,075	32,321,603	1,317,311	1,288,752
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	3,714,375,216	3,518,067,668	33,079,075	32,321,603	1,317,311	1,288,752
15	Other Operating Revenues						
16	(450) Forfeited Discounts	3,648	108,171				
17	(451) Miscellaneous Service Revenues	[b]3,048,654	[b]2,809,347				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	1,430,408	1,531,046				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[a]5,638,786	[a]3,310,358				
22	(456.1) Revenues from Transmission of Electricity of Others	99,405,830	66,157,396				

23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	109,527,326	73,916,318				
27	TOTAL Electric Operating Revenues	3,823,902,542	3,591,983,986				

Line12, column (b) includes $ [1]1,816,805 of unbilled revenues.
Line12, column (d) includes [1](19,510) MWH relating to unbilled revenues

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FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

(b) Concept: MiscellaneousServiceRevenues

Connection Charges	$	2,692,992
TSMC Project Temp Power		248,066
Other		107,596
Total	$	3,048,654

(c) Concept: OtherElectricRevenue

(456) - PCS Project	$	2,987,068
(456) - Bid Fee Proceeds		1,190,000
(456) - Management/Administration Fees		1,537,208
(456) - Fuel Loading		1,280,656
(456) - Facility Charges		462,257
(456) - Participant Station Power Revenue		153,705
(456) - Other		165,027
(456) - Call Center Referrals		99,250
(456) - Surepay and Autopay Discount		(2,236,385)
Total	$	5,638,786

(d) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

(e) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

(f) Concept: MiscellaneousServiceRevenues

Connection Charges	$	2,790,720
Other		18,627
Total	$	2,809,347

(g) Concept: OtherElectricRevenue

(456) - PCS Project	$	2,688,999
(456) - Fuel Loading		1,257,366
(456) - Management/Administration Fees		631,466
(456) - Facility Charges		254,964
(456) - Bid Fee Proceeds		170,000
(456) - Participant Station Power Revenue		147,947
(456) - Other		137,402
(456) - Interconnection Study Fee		100,000
(456) - Surepay and Autopay Discount		(2,077,786)
Total	$	3,310,358

(h) Concept: MegawattHoursSoldSmallOrCommercial

Amounts reported for prior year sales have been updated to reflect corrected sales data.

(i) Concept: MegawattHoursSoldLargeOrIndustrial

Amounts reported for prior year sales have been updated to reflect corrected sales data.

(j) Concept: RevenueFromSalesOfElectricityUnbilled

Unbilled Revenue		
1440-100 Residential	$	(3,718,357)
1442-100 Commercial		3,428,939
1442-102 Industrial		2,068,480
1442-104 Irrigation		(8,230)
1440-100 Hwy lighting		45,973
	$	1,816,805

(k) Concept: MegawattHoursOfElectricitySoldUnbilled

Unbilled Revenue	
1440-100 Residential	(42,987)
1442-100 Commercial	6,280
1442-102 Industrial	16,994
1442-104 Irrigation	(53)
1440-100 Hwy lighting	256
	(19,510)

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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2					
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4					
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41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	R-XS	1,953,115	271,313,879	308,722	6,326	0.1389
2	R-BASIC	879,362	125,968,107	88,533	9,933	0.1432
3	R-BASICL	378,278	56,254,542	20,388	18,554	0.1487
4	R-TOU-E	4,217,795	596,226,730	312,059	13,516	0.1414
5	R-2	1,298,032	174,862,577	88,092	14,735	0.1347
6	R-3	4,564,558	549,110,112	238,087	19,172	0.1203
7	R-TECH	584	81,584	22	26,545	0.1397
8	E-12 EPR-2,6	105,188	18,420,813	29,855	3,523	0.1751
9	ET-1 EPR-2,6	69,287	8,864,605	9,566	7,243	0.1279
10	ET-2 EPR-2,6	280,468	35,135,568	34,163	8,210	0.1253
11	ECT-1R EPR-2,6	3,282	499,528	211	15,555	0.1522
12	ECT-2 EPR-2,6	17,869	2,733,366	1,296	13,788	0.1530
13	R-TOU-E RCP	336,759	53,877,028	33,574	10,030	0.1600
14	R-2 RCP	83,177	12,327,617	7,265	11,449	0.1482
15	R-3 RCP	77,103	10,733,980	5,479	14,072	0.1392
16	R-TECH RCP	339	46,083	31	10,935	0.1359
17	E-47	1,501	503,299			0.3353
18	Green Power		83,141			
41	TOTAL Billed Residential Sales	14,266,697	1,917,042,559	1,177,343	12,118	0.1344
42	TOTAL Unbilled Rev. (See Instr. 6)	(42,986)	(3,718,348)			0.0865
43	TOTAL	14,223,711	1,913,324,211	1,177,343	12,081	0.1345

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	E-20	29,914	3,891,051	352	84,983	0.1301
2	E-30	4,631	1,253,778	4,204	1,102	0.2707
3	E-32 XS	1,612,497	248,103,714	103,675	15,553	0.1539
4	E-32 XSD	40,391	5,244,892	1,410	28,646	0.1299
5	E-32 S	2,423,772	310,476,224	17,705	136,898	0.1281
6	E-32 M	2,889,653	304,399,196	3,582	806,715	0.1053
7	E-32 L	2,038,868	182,445,696	570	3,576,961	0.0895
8	E-32TXS	20,829	2,963,894	646	32,243	0.1423
9	E-32TOUS	27,859	3,674,289	143	194,818	0.1319
10	E-32TOUM	91,661	9,565,168	84	1,091,202	0.1044
11	E-32TOUL	189,674	16,813,900	42	4,516,048	0.0886
12	GS-SCHM	72,640	9,717,506	126	576,508	0.1338
13	GS-SCHL	29,047	3,211,239	20	1,452,350	0.1106
14	E-34	385,279	27,933,215	13	29,636,846	0.0725
15	E-35	479,584	37,264,515	14	34,256,000	0.0777
16	E-221	328,928	33,192,338	1,197	274,794	0.1009
17	E-47	18,141	8,192,514			0.4516
18	Green Power		1,037,973			
19	EPR-2	9,009	892,316	28	321,750	0.0990
20	EPR-6	607,843	69,040,052	1,547	392,917	0.1136
21	E-56	238	611,736	1	238,000	2.5703
22	E-56 R	153,936	13,622,954	26	5,920,615	0.0885
23	E-32 M AG-X	50,416	4,093,557	31	1,626,323	0.0812
24	E-32 L AG-X	317,582	31,004,515	71	4,472,986	0.0976
25	E-34 AG-X	60,570	5,668,380	2	30,285,000	0.0936
26	(a) E-35 AG-X	840,443	52,698,340	14	60,031,643	0.0627
41	TOTAL Billed Small or Commercial	12,723,405	1,387,012,952	135,503	93,898	0.1090

42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	6,280	3,428,950			0.5460
43	TOTAL Small or Commercial	12,729,685	1,390,441,902	135,503	93,944	0.1092

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

*XHLF, E-35 AG-X and Special Contracts included under E-35 AG-X due to low number of customers

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	E-30	58	19,205	78	744	0.3311
2	E-32 XS	27,987	4,299,928	1,837	15,235	0.1536
3	E-32 XSD	242	30,449	6	40,333	0.1258
4	E-32 S	70,993	10,045,991	578	122,825	0.1415
5	E-32 M	160,933	18,942,994	255	631,110	0.1177
6	E-32 L	464,920	41,082,815	112	4,151,071	0.0884
7	E-32TXS	765	112,354	5	153,000	0.1469
8	E-32TOUS	2,659	265,688	7	379,857	0.0999
9	E-32TOUM	6,208	716,741	7	886,857	0.1155
10	E-32TOUL	46,923	3,763,452	6	7,820,500	0.0802
11	E-34	50,407	3,789,901	2	25,203,500	0.0752
12	E-35	674,721	46,704,046	15	44,981,400	0.0692
13	E-36 XL	58,666	4,495,092	5	11,733,200	0.0766
14	E-221	9,918	995,386	69	143,739	0.1004
15	E-47	490	152,749			0.3117
16	EPR-6	32,714	3,745,541	31	1,055,290	0.1145
17	[a] E-35 AG-X	540,285	34,988,822	6	90,047,500	0.0648
41	TOTAL Billed Large (or Ind.) Sales	2,148,889	174,151,154	3,019	711,788	0.0810
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	16,941	2,060,251			0.1216
43	TOTAL Large (or Ind.)	2,165,830	[b]176,211,405	3,019	717,400	0.0814

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

*XHLF, E-35 AG-X and Special Contracts included under E-35 AG-X due to low number of customers

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
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41	TOTAL Billed Commercial and Industrial Sales	14,872,294	1,561,164,106	138,522	107,364	0.1050
42	TOTAL Unbilled Rev. (See Instr. 6)	23,221	5,489,201			0.2364
43	TOTAL	14,895,515	1,566,653,307	138,522	107,532	0.1052

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Public Street Lighting	106,869	20,107,983	1,266	84,415	0.1882
41	TOTAL Billed Public Street and Highway Lighting	106,869	20,107,983	1,266	84,415	0.1882
42	TOTAL Unbilled Rev. (See Instr. 6)	255	45,952			0.1802
43	TOTAL	107,124	20,153,935	1,266	84,616	0.1881

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	445 Other Public Authorities	1,886	132,468	135	13,970	0.0702
41	TOTAL Billed Other Sales to Public Authorities	1,886	132,468	135	13,970	0.0702
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	1,886	132,468	135	13,970	0.0702

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	29,247,746	3,498,447,116	1,317,266	22,203	0.1196
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(19,510)	1,816,805			(0.0931)
43	TOTAL - All Accounts	29,228,236	3,500,263,921	1,317,266	22,203	0.1198

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	Aguila Irrigation District	RQ	86308								
2	Buckeye Irrigation District	RQ	86306								
3	Electrical District 6	RQ	86307								
4	Electrical District 7	RQ	86304								
5	Electrical District 8	RQ	86310								
6	Harquahala Valley Irrigation District	RQ	86309								
7	Maricopa County Municipal District	RQ	86058								
8	McMullen Valley Irrigation District	RQ	86311								
9	Roosevelt Irrigation District	RQ	86305								
10	Tonopah Irrigation District	RQ	86312								
11	Town of Wickenburg	RQ	85736								
12	Tohono O Odham Utility Authority	RQ	87975								

13	Arizona Electric Power Cooperative Inc	SF	WSPP				232,070		5,503,152		5,503,152
14	Avangrid Renewables, LLC	SF	WSPP				62,419		2,912,964		2,912,964
15	Bonneville Power Administration	SF	WSPP				31,600		1,634,000		1,634,000
16	BP Energy Company	SF	WSPP				214,390		12,024,797		12,024,797
17	Brookfield Renewable Trading and Marketing LP	SF	WSPP				11,424		761,672		761,672
18	California Independent System Operator	SF	MRT-Vol 3				1,340,946		74,940,830		74,940,830
19	Calpine Energy Solutions, LLC	SF	WSPP				128		4,993		4,993
20	Central Arizona Water Conservation District	SF	WSPP				152,540		4,009,204		4,009,204
21	Citigroup Energy Inc.	SF	WSPP				46,984		1,685,899		1,685,899
22	Colorado River Storage Project (WAPA)	SF	WSPP				200		17,360		17,360
23	ConocoPhillips Company	SF	WSPP				49,861		3,799,236		3,799,236
24	Constellation New Energy Inc.	SF	WSPP				36		1,475		1,475
25	Direct Energy Business LLC	SF	WSPP				130		24,151		24,151
26	DTE Energy Trading, Inc.	SF	WSPP				185,834		10,378,528		10,378,528
27	Dynasty Power Inc.	SF	WSPP				5,200		217,316		217,316
28	EDF Trading North America LLC	SF	WSPP				233,412		13,442,265		13,442,265
29	El Paso Electric	SF	WSPP								
30	Energy Keepers, Inc.	SF	WSPP								
31	Exelon Generation Company, LLC	SF	WSPP				127,600		6,623,168		6,623,168
32	Freeport-McMoRan Copper & Gold Energy Services LLC	SF	WSPP				1,308		118,160		118,160
33	Guzman Energy LLC	SF	WSPP				786		36,375		36,375
34	Guzman Renewable Energy Partners LLC	SF	WSPP				25		1,875		1,875
35	Idaho Power Company	SF	WSPP				58,140		3,219,891		3,219,891
36	Imperial Irrigation District	SF	WSPP				7,400		367,108		367,108
37	Los Alamos County	SF	WSPP				17		750		750
38	Los Angeles Department of Water & Power	SF	WSPP				5,300		214,390		214,390
39	Macquarie Energy LLC	SF	WSPP				273,581		15,416,022		15,416,022
40	Morgan Stanley Capital Group Inc.	SF	MRT Vol 3				174,644		7,811,421		7,811,421
41	Nevada Power Company	SF	WSPP				36		2,340		2,340
42	NextEra Energy Power Marketing LLC	SF	WSPP				292		31,454		31,454
43	PacifiCorp	SF	WSPP				25,097		2,360,572		2,360,572
44	Portland General Electric Company	SF	WSPP				29,402		2,443,686		2,443,686
45	Powerex Corp.	SF	WSPP				35,554		6,772,168		6,772,168
46	Public Service Company of Colorado	SF	WSPP				119,718		5,181,978		5,181,978
47	Public Service Company of New Mexico	SF	WSPP				1,475		111,363		111,363
48	Rainbow Energy Marketing Corporation	SF	WSPP				5,680		210,034		210,034
49	Salt River Project	SF	WSPP				123,080		1,836,365		1,836,365

50	Sempra Gas & Power Marketing, LLC	SF	WSPP				100		35,000		35,000
51	Shell Energy North America (US), L.P.	SF	WSPP				44,166		1,936,796		1,936,796
52	Southwest Reserve Sharing Group	SF	0				5,331		197,569		197,569
53	Tenaska Power Services Company	SF	WSPP				128,945		6,486,533		6,486,533
54	The Energy Authority, Inc.	SF	WSPP				9,320		254,223		254,223
55	TransAlta Energy Marketing, U.S., Inc.	SF	WSPP				88,553		4,406,115		4,406,115
56	TransCanada Energy Sales, LTD	SF	WSPP				491		33,350		33,350
57	Tri-State Generation and Transmission Association, Inc.	SF	WSPP				200		10,800		10,800
58	Tucson Electric Power	SF	WSPP				12,985		745,837		745,837
59	UNS Electric	SF	WSPP				3,400		153,392		153,392
60	Vitol Inc.	SF	WSPP				400		14,000		14,000
61	Western Area Power Administration Desert Southwest Region	SF	WSPP				640		58,380		58,380
62	PacifiCorp	OS	WSPP								
63	Transmission Loss	OS	0						17,374,714		17,374,714
64	Transmission Suballocation	OS	0						(2,289,615)		(2,289,615)
65	Miscellaneous Power Customers	AD	0						577,239		577,239
15	Subtotal - RQ										
16	Subtotal-Non-RQ						3,850,839		214,111,295		214,111,295
17	Total						3,850,839		214,111,295		214,111,295

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	7,872,520	7,565,273
5	(501) Fuel	264,828,137	216,626,250
6	(502) Steam Expenses	28,295,713	27,359,341
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,913,646	1,210,525
10	(506) Miscellaneous Steam Power Expenses	15,290,880	20,997,377
11	(507) Rents	1,558,067	1,508,864
12	(509) Allowances	7,821,132	3,185,982
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	327,580,095	278,453,612
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,968,139	4,985,725
16	(511) Maintenance of Structures	13,887,307	11,345,054
17	(512) Maintenance of Boiler Plant	30,352,361	28,115,307
18	(513) Maintenance of Electric Plant	6,912,240	5,647,184
19	(514) Maintenance of Miscellaneous Steam Plant	7,088,968	6,979,320
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	64,209,015	57,072,590
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	391,789,110	335,526,202
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	20,261,893	22,031,036
25	(518) Fuel	62,204,380	65,811,812
26	(519) Coolants and Water	14,744,174	13,970,772
27	(520) Steam Expenses	8,577,300	9,017,147
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	10,603,066	11,545,250

31	(524) Miscellaneous Nuclear Power Expenses	39,199,639	42,548,659
32	(525) Rents	21,271,091	22,759,215
33	TOTAL Operation (Enter Total of lines 24 thru 32)	176,861,543	187,683,891
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	5,716,267	4,496,895
36	(529) Maintenance of Structures	2,463,752	2,361,295
37	(530) Maintenance of Reactor Plant Equipment	11,077,706	11,989,346
38	(531) Maintenance of Electric Plant	11,596,663	10,877,178
39	(532) Maintenance of Miscellaneous Nuclear Plant	3,752,370	3,343,692
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	34,606,758	33,068,406
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	211,468,301	220,752,297
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	11,371,887	13,311,539
63	(547) Fuel	458,329,522	317,732,099
64	(548) Generation Expenses	9,610,837	10,527,689
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	56,672,897	48,502,303
66	(550) Rents	568,855	579,073

67	TOTAL Operation (Enter Total of Lines 62 thru 67)	536,553,998	390,652,703
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,709,228	1,409,419
70	(552) Maintenance of Structures	7,442,557	6,101,887
71	(553) Maintenance of Generating and Electric Plant	35,547,139	33,541,264
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,270,485	2,773,022
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	46,969,409	43,825,592
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	583,523,407	434,478,295
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	349,775,674	361,383,944
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	(3,037,121)	(3,092,797)
78	(557) Other Expenses	(193,828)	3,436,452
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	346,544,725	361,727,599
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,533,325,543	1,352,484,393
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,838,370	1,283,856
85	(561.1) Load Dispatch-Reliability	3,480,707	3,513,803
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,672,318	3,548,393
87	(561.3) Load Dispatch-Transmission Service and Scheduling	867,406	880,984
88	(561.4) Scheduling, System Control and Dispatch Services	2,579,783	2,873,335
89	(561.5) Reliability, Planning and Standards Development	2,429,091	2,195,522
90	(561.6) Transmission Service Studies	554	249
91	(561.7) Generation Interconnection Studies	85,649	75,936
92	(561.8) Reliability, Planning and Standards Development Services	825,643	473,349
93	(562) Station Expenses	910,757	857,683
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	1,936,656	3,007,318
95	(564) Underground Lines Expenses	42,154	34,409
96	(565) Transmission of Electricity by Others	35,681,215	37,915,120
97	(566) Miscellaneous Transmission Expenses	13,101,515	13,422,416
98	(567) Rents	8,413,296	8,428,559
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	77,865,114	78,510,932
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	589,055	556,440

102	(569) Maintenance of Structures	1,007,742	899,005
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment	194,724	174,939
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,444,376	5,130,777
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	3,780,379	3,078,230
109	(572) Maintenance of Underground Lines	295,013	457,980
110	(573) Maintenance of Miscellaneous Transmission Plant	13,285	7,974
111	TOTAL Maintenance (Total of Lines 101 thru 110)	10,324,574	10,305,345
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	88,189,688	88,816,277
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	675,587	496,530
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	675,587	496,530
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	675,587	496,530
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,887,919	3,671,342
135	(581) Load Dispatching	2,300,291	2,349,198
136	(582) Station Expenses	1,123,148	1,064,361
137	(583) Overhead Line Expenses	954,509	774,719

138	(584) Underground Line Expenses	1,545,349	1,050,005
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	691	2,627
140	(586) Meter Expenses	9,667,513	8,737,832
141	(587) Customer Installations Expenses	18,967	8,362
142	(588) Miscellaneous Expenses	50,536,611	58,362,614
143	(589) Rents	742,640	924,485
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	69,777,638	76,945,545
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	712,180	623,277
147	(591) Maintenance of Structures	248	14,002
148	(592) Maintenance of Station Equipment	5,252,120	6,700,444
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	20,133,142	21,666,437
150	(594) Maintenance of Underground Lines	8,011,299	7,527,510
151	(595) Maintenance of Line Transformers	2,354,404	2,114,464
152	(596) Maintenance of Street Lighting and Signal Systems	670,652	354,026
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	2,416,638	2,656,235
155	TOTAL Maintenance (Total of Lines 146 thru 154)	39,550,683	41,656,395
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	109,328,321	118,601,940
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	5,928,654	6,399,886
160	(902) Meter Reading Expenses	1,527,836	1,775,928
161	(903) Customer Records and Collection Expenses	42,889,950	40,506,307
162	(904) Uncollectible Accounts	22,250,562	20,633,499
163	(905) Miscellaneous Customer Accounts Expenses	568,796	715,945
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	73,165,798	70,031,565
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	130,809	790,692
168	(908) Customer Assistance Expenses	52,919,641	48,057,580
169	(909) Informational and Instructional Expenses	251,607	824,134
170	(910) Miscellaneous Customer Service and Informational Expenses	1,503,350	1,071,381
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	54,805,407	50,743,787
172	7. SALES EXPENSES		

173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	7,984,400	7,988,344
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	5,676,087	5,721,338
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	13,660,487	13,709,682
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	105,907,224	106,334,441
182	(921) Office Supplies and Expenses	1,262,715	9,371,202
183	(Less) (922) Administrative Expenses Transferred-Credit	28,000,000	23,484,092
184	(923) Outside Services Employed	58,956,402	60,339,694
185	(924) Property Insurance	4,409,288	1,181,103
186	(925) Injuries and Damages	8,439,802	9,469,049
187	(926) Employee Pensions and Benefits	(16,278,579)	36,155,642
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	22,095,423	19,919,413
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	7,154,627	5,184,391
192	(930.2) Miscellaneous General Expenses	(59,042,295)	(65,317,601)
193	(931) Rents	6,333,885	6,020,060
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	111,238,492	165,173,302
195	Maintenance		
196	(935) Maintenance of General Plant	13,244,176	13,110,620
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	124,482,668	178,283,922
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,997,633,499	1,873,168,096

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	PacifiCorp	EX	182						0	211,766		(6,499,892)		(6,499,892)
2	Electrical District #6	EX	126											
3	Electrical District #7	EX	128											
4	Electrical District #8	EX	140											
5	Aguila Irrigation District	EX	141											
6	Buckey Water Conservation & Drainage	EX	155											
7	Harquahala Valley Power District	EX	153											
8	Maricopa Cith Municipal Water Conservation	EX	168											
9		EX	142											

	McMullen Valley Water Conservation District													
10	Roosevelt Irrigation District	EX	158											
11	Tonopah Irrigation District	EX	143											
12	Arlington Valley LLC	RQ		413,580			1,045,569				35,489,201		4,067,268	39,556,469
13	Griffith Energy LLC	RQ		410,400			1,006,104				33,393,938		5,266,716	38,660,654
14	South Point Energy Center LLC	RQ		340,027			1,417,973				36,879,356		5,427,420	42,306,776
15	Salt River Project	RQ					180,642					11,265,214		11,265,214
16	Ajo Improvement Company	RQ					20					1,647		1,647
17	Aragonne Wind LLC	LU					65,213					3,430,863		3,430,863
18	Arizona Electric Power Cooperative Inc	SF					16,529					881,487		881,487
19	Arizona Solar One, LLC	LU					694,570					99,731,475		99,731,475
20	Avangrid Renewables, LLC	SF					2,144					1,158,385		1,158,385
21	Bonneville Power Administration	SF					932					37,600		37,600
22	BP Energy Company	SF					21,757					3,051,907		3,051,907
23	Brookfield Renewable Trading and Marketing LP	IF					31,614					2,598,439		2,598,439
24	California Independent System Operator	SF					980,542					41,494,426	5,680,860	47,175,286
25	California Power Exchange Corp	SF					0					0	52,501	52,501
26	Calpine Energy Services, LP	SF					0				0	0		
27	Calpine Energy Solutions, LLC	IF					92,577					4,971,454		4,971,454
28	CE Turbo LLC	LU					55,714					4,074,725		4,074,725
29	Central Arizona Water Conservation District	SF					3,618					147,428		147,428
30	Citigroup Energy Inc.	SF					6					124		124
31	City of Glendale Water & Power	SF					0					0		
32	Colorado River Storage Project (WAPA)	SF					0					0		
33	ConocoPhillips Company	SF					2,298					174,698		174,698
34	Constellation New Energy Inc.	IF					98,689					3,431,452		3,431,452
35	Desert Sky Solar, LLC	LU					37,903					3,237,492		3,237,492
36	Direct Energy Business LLC	IF					157,378					7,081,896		7,081,896
37	DTE Energy Trading, Inc.	SF					870					52,816		52,816
38	Dynasty Power Inc.	SF					154					5,989		5,989
39	EDF Trading North America LLC	SF					5,176					2,117,926		2,117,926
40	El Paso Electric	SF					260					24,700		24,700
41	Energy Keepers, Inc.	SF					0					0		
42	Evergy Kansas Central, Inc.	SF					0					0		
43		SF					1,191					66,164		66,164

	Exelon Generation Company, LLC													
44	Freeport-McMoRan Copper & Gold Energy Services LLC	IF					470,518					22,146,057		22,146,057
45	Guzman Energy LLC	SF					1,735					111,796		111,796
46	High Lonesome Mesa LLC	LU					369,220					18,890,036		18,890,036
47	Idaho Power Company	SF					25					795		795
48	Los Angeles Department of Water & Power	SF					28,465					919,578		919,578
49	Macquarie Energy LLC	SF					16,493					3,092,777		3,092,777
50	Morgan Stanley Capital Group Inc.	SF					35,670					2,496,737		2,496,737
51	Navajo Tribal Utility Authority	SF		7			2,599					447,201		447,201
52	Nevada Power Company	SF					6,675					425,650		425,650
53	NextEra Energy Power Marketing LLC	IF					140,300					9,123,623		9,123,623
54	Novo BioPower LLC	LU					110,338					12,234,078		12,234,078
55	PacifiCorp	SF					6,637					408,826		408,826
56	Perrin Ranch Wind LLC	LU					208,432					17,560,371		17,560,371
57	Portland General Electric Company	SF					36					714		714
58	Powerex Corp.	SF					408,572					52,082,233		52,082,233
59	Public Service Company of Colorado	SF					2,800					183,760		183,760
60	Public Service Company of New Mexico	SF					4,900					212,788		212,788
61	Rainbow Energy Marketing Corporation	SF					0					0		
62	RE Ajo 1 LLC	LU					8,614					1,408,787		1,408,787
63	RE Bagdad Solar 1 LLC	LU					32,476					5,903,554		5,903,554
64	RE Gillespie 1, LLC	LU					39,920					3,361,647		3,361,647
65	Salt River Project	SF		141,564			422,466				26,251,884	2,574,503	1,952,650	30,779,037
66	Sempra Gas & Power Marketing, LLC	SF					400					140,000		140,000
67	Shell Energy North America (US), L.P.	SF					17,353					981,079		981,079
68	SunE AZ 1 LLC	LU					22,752					3,094,729		3,094,729
69	SunE AZ 2 LLC	LU					34,303					3,738,274		3,738,274
70	Tenaska Power Services Company	SF					11,627					1,038,894		1,038,894
71	The Energy Authority, Inc.	SF					457					22,176		22,176
72	TransAlta Energy Marketing, U.S., Inc.	SF					9,525					4,257,891		4,257,891
73	TransCanada Energy Sales, LTD	SF					400					140,000		140,000
74		SF					0					0		

	Tri-State Generation and Transmission Association, Inc.													
75	Tucson Electric Power	SF					60,818					2,144,643		2,144,643
76	UNS Electric	SF					3,225					127,758		127,758
77	Waste Management Renewable Energy, LLC	LU					19,338					1,789,901		1,789,901
78	Western Area Power Administration Desert Southwest Region	OS					40						438,900	438,900
79	Banked Energy	OS					(15,794)					280,560		280,560
80	Co-Generation	OS					436,777					3,237,833		3,237,833
81	Electrical District #3	OS					2,756					206,179		206,179
82	Purchased Power - Distributed Energy	OS										46,260,365		46,260,365
83	Power Financials	OS											0	
84	Power Supply Adjustor	OS											(207,887,771)	(207,887,771)
85	SFAS 133	OS											(641,511)	(641,511)
86	Southwest Reserve Sharing Group	SF					2,351					115,623		115,623
87	Miscellaneous Power Customers	AD					(1,081)					(380,533)	84,964	(295,569)
15	TOTAL						8,841,581	0	0	211,766	132,014,379	403,319,298	(185,558,003)	349,775,674

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	[a] Arizona Public Service Company	Arizona Public Service Company	[d] Arizona Public Service Company	FNS	OATT	Various	Various	[a] 0	27,448,732	27,448,732			[b] 0	
2	[b] Arizona Public Service Company	Arizona Public Service Company	[e] Arizona Public Service Company	FNS	OATT	Various	Various	[b] 0					[c] (292,907,480)	(292,907,480)
3	[c] Arizona Public Service Company	Arizona Public Service Company	[f] Arizona Public Service Company	FNS	OATT	Various	Various	[c] 0					[a] 292,907,480	292,907,480
4	Ajo Improvement Company	Not Available	Not Available	FNO	OATT	Various	Various	3	13,104	13,104	97,789	4,389	[d] (146)	102,032
5	City of Williams	Not Available	Not Available	FNO	OATT	Various	Various	9	48,767	48,767	295,341	17,455	[e] 64,639	377,435
6	Navajo Tribal Utility Authority	Tucson Electric Power	Navajo Tribal Utility Authority	FNO	OATT	Various	Various	9	62,548	62,548	309,957	15,499	[a] 52,391	377,847
7	Navopache Electric Cooperative, Inc.	Not Available	Not Available	FNO	OATT	Various	Various	63	221,340	221,340	2,217,202		[a] (5,516)	2,211,686
8	Southwest Public Power Agency	Not Available	Not Available	FNO	OATT	Various	Various	152	642,154	642,154	5,461,527	271,747	[a] 6,317,132	12,050,406
9	TOUA	Not Available	Not Available	FNO	OATT	Various	Various	14	63,458	63,458	484,783	24,480	[a] 5,857	515,120
10	Broadview Energy JN LLC	Not Available	Not Available	LFP	OATT	Various	Various	167	670,011	670,011	6,250,292		[a] (11,257)	6,239,035
11	Broadview Energy KW- LLC	Not Available	Not Available	LFP	OATT	Various	Various	130	538,323	538,323	4,871,846		[aa] (7,910)	4,863,936
12	Clines Corners Wind Farm LLC	Not Available	Not Available	LFP	OATT	Various	Various	120	60,135	60,135	566,032		0	566,032
13	CSE Operating 1, LLC	Not Available	Not Available	LFP	OATT	Various	Various	1	7,587	7,587	37,531	1,176	[ab] 14,753	53,460
14	Duran Mesa Wind LLC	Not Available	Not Available	LFP	OATT	Various	Various	51	22,801	22,801	156,889		0	156,889
15	El Cabo Wind	Not Available	Not Available	LFP	OATT	Various	Various	300	1,066,445	1,066,445	11,259,278		[ac] (17,460)	11,241,818
16	Electrical District 3	Not Available	Not Available	LFP	OATT	Various	Various	90	395,803	395,803	3,378,232		[ad] (7,190)	3,371,042

17	Grady Wind Energy Center-LLC	Not Available	Not Available	LFP	OATT	Various	Various	200	838,485	838,485	7,506,185		(13,941)	7,492,244
18	NOVO BioPower LLC	Not Available	Not Available	LFP	OATT	Various	Various	14	103,925	103,925	525,503		(323)	525,180
19	Public Service Company of New Mexico	Not Available	Not Available	LFP	OATT	Various	Various	145	260,212	260,212	5,441,984		(5,656)	5,436,328
20	Salt River Project	Not Available	Not Available	LFP	OATT	Various	Various	127	215,546	215,546	4,766,747		6,226	4,772,973
21	Tecolote Wind LLC	Not Available	Not Available	LFP	OATT	Various	Various	132	75,594	75,594	406,067		0	406,067
22	Trico Electric Cooperative Inc.	Not Available	Not Available	LFP	OATT	Various	Various	2	15,770	15,770	75,062		(251)	74,811
23	Tucson Electric Power Company	Not Available	Not Available	LFP	OATT	Various	Various	110	142,087	142,087	4,128,950		(1,465)	4,127,485
24	Tecolote Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	0					419,210	419,210
25	Duran Mesa LLC	Not Available	Not Available	SFP	OATT	Various	Various	0					161,968	161,968
26	Clines Corners Wind Farm LLC	Not Available	Not Available	SFP	OATT	Various	Various	0					381,100	381,100
27	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	SFP	OATT	Various	Various	10			49,021		0	49,021
28	EDF Trading North America, LLC	Not Available	Not Available	SFP	OATT	Various	Various	125	51,257	51,257	1,593,183		(337)	1,592,846
29	Imperial Irrigation District Marketing	Not Available	Not Available	SFP	OATT	Various	Various	80	17,886	17,886	1,287,475		(3)	1,287,472
30	Macquarie Energy LLC	Not Available	Not Available	SFP	OATT	Various	Various	50	6,412	6,412	735,315		(146)	735,169
31	Mercuria Energy America LLC	Not Available	Not Available	SFP	OATT	Various	Various	50	43,686	43,686	906,889		(435)	906,454
32	Nevada Power Company	Not Available	Not Available	SFP	OATT	Various	Various	350	155,855	155,855	1,715,735		(1,440)	1,714,295
33	PacifiCorp	Not Available	Not Available	SFP	OATT	Various	Various	400	209,703	209,703	5,514,863		(2,339)	5,512,524
34	Powerex	Not Available	Not Available	SFP	OATT	Various	Various	364	315,725	315,725	3,806,615		(1,360)	3,805,255
35	Salt River Project	Not Available	Not Available	SFP	OATT	Various	Various	275	94,450	94,450	1,348,078		0	1,348,078
36	Western Area Power Administration (DSW)	Not Available	Not Available	SFP	OATT	Various	Various	81	87,464	87,464	774,532		0	774,532
37	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	SFP	OATT	Various	Various	15	696	696	5,577		0	5,577
38	Arizona Public Service Company	Not Available	Not Available	SFP	OATT	Various	Various	147	3,492	3,492	17,744		1	17,745
39	Avangrid Renewables, LLC	Not Available	Not Available	SFP	OATT	Various	Various	1,077	16,264	16,264	261,019		0	261,019
40	Brookfield Renewable Trading and Marketing LP	Not Available	Not Available	SFP	OATT	Various	Various	100	3,427	3,427	33,403		0	33,403
41	Clines Corners Wind Farm LLC	Not Available	Not Available	SFP	OATT	Various	Various	1,568	29,535	29,535	178,960		0	178,960
42	Duran Mesa Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	432	9,030	9,030	48,277		0	48,277
43	Dynasty Power Inc	Not Available	Not Available	SFP	OATT	Various	Various	450	10,850	10,850	66,807		0	66,807
44	EDF Trading North America, LLC	Not Available	Not Available	SFP	OATT	Various	Various	125	6,204	6,204	59,486		(277)	59,209
45	Guzman Power Markets LLC	Not Available	Not Available	SFP	OATT	Various	Various	500	10,504	10,504	96,262		0	96,262
46	Guzman Renewable Energy Partners	Not Available	Not Available	SFP	OATT	Various	Various	120	4,055	4,055	24,181		0	24,181

47	Imperial Irrigation District Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[ep]50	1,602	1,602	20,239		0	20,239
48	Los Angeles Wholesale Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[ab]260	7,059	7,059	68,925		0	68,925
49	Macquarie Energy LLC	Not Available	Not Available	SFP	OATT	Various	Various	[ai]640	4,806	4,806	56,074		0	56,074
50	Mercuria Energy America LLC	Not Available	Not Available	SFP	OATT	Various	Various	[al]558	12,187	12,187	159,560		0	159,560
51	Morgan Stanley	Not Available	Not Available	SFP	OATT	Various	Various	[ak]365	6,140	6,140	42,705		0	42,705
52	Nevada Power Company	Not Available	Not Available	SFP	OATT	Various	Various	[ai]150	2,375	2,375	28,845		0	28,845
53	PacifiCorp	Not Available	Not Available	SFP	OATT	Various	Various	[am]4,048	116,192	116,192	1,349,087		0	1,349,087
54	Powerex	Not Available	Not Available	SFP	OATT	Various	Various	[an]200	3,495	3,495	25,108		0	25,108
55	Rainbow Energy Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[ao]290	3,980	3,980	39,208		0	39,208
56	Red Cloud Wind Farm	Not Available	Not Available	SFP	OATT	Various	Various	[ap]480	7,935	7,935	55,619		[qw](615)	55,004
57	Salt River Project	Not Available	Not Available	SFP	OATT	Various	Various	[aq]725	4,830	4,830	139,418		0	139,418
58	Shell Energy North America LP	Not Available	Not Available	SFP	OATT	Various	Various	[ar]525	11,706	11,706	169,372		[qz](58)	169,314
59	Southern California Edison Company	Not Available	Not Available	SFP	OATT	Various	Various	[as]265	5,681	5,681	31,988		0	31,988
60	Tecolote Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	[at]245	4,561	4,561	27,445		0	27,445
61	Tenaska Power Services Co.	Not Available	Not Available	SFP	OATT	Various	Various	[au]4,373	97,320	97,320	783,913		[qy](109)	783,804
62	The Energy Authority Inc.	Not Available	Not Available	SFP	OATT	Various	Various	[av]10	274	274	2,068		0	2,068
63	TransAlta Energy Marketing U.S. Inc.	Not Available	Not Available	SFP	OATT	Various	Various	[aw]50	2,306	2,306	18,082		0	18,082
64	UNIPER GLOBAL COMMODITIES NORTH AMERICA LLC	Not Available	Not Available	SFP	OATT	Various	Various	[ax]362	13,913	13,913	90,926		[qz](447)	90,479
65	Western Area Power Administration (DSW)	Not Available	Not Available	SFP	OATT	Various	Various	[ay]280	14,380	14,380	108,018		[ra](142)	107,876
66	Guzman Power Markets LLC	Not Available	Not Available	SFP	OATT	Various	Various	[az]30	3,169	3,169	45,229		[rb](103)	45,126
67	Imperial Irrigation District Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[ba]15	2,385	2,385	10,642		0	10,642
68	Macquarie Energy LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bb]75	1,350	1,350	53,210.00		0	53,210.00
69	Mercuria Energy America LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bc]3	329	329	2,214		0	2,214
70	Nevada Power Company	Not Available	Not Available	SFP	OATT	Various	Various	[bd]100	7,156	7,156	113,072		0	113,072
71	Red Cloud Wind Farm	Not Available	Not Available	SFP	OATT	Various	Various	[be]100	8,238	8,238	70,946		0	70,946
72	Salt River Project	Not Available	Not Available	SFP	OATT	Various	Various	[bf]822	42,280	42,280	929,452		0	929,452
73	Western Area Power Administration (DSW)	Not Available	Not Available	SFP	OATT	Various	Various	[bg]35	10,920	10,920	73,497		[rc](1,125)	72,372
74	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	SFP	OATT	Various	Various	[bh]1,161	2,457	2,457	20,620		[rd](95)	20,525
75	Arizona Public Service Company	Not Available	Not Available	SFP	OATT	Various	Various	[bi]6,704	12,023	12,023	89,759		[re](47)	89,712
76	Avangrid Renewables, LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bj]148	186	186	2,034		[rf](118)	1,916
77	Broadview Energy JN LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bk]260			[rh](108,937)		0	(108,937)
78	Broadview Energy KW- LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bl]1,135	13	13	[ri](78,923)		0	(78,923)

79	Brookfield Energy Marketing LP	Not Available	Not Available	SFP	OATT	Various	Various	[bm]0					0	
80	Brookfield Renewable Trading and Marketing LP	Not Available	Not Available	SFP	OATT	Various	Various	[bn]1,950	4,448	4,448	36,627		[bo](92)	36,535
81	Central Arizona Water Conservation District	Not Available	Not Available	SFP	OATT	Various	Various	[bp]195	195	195	1,470		0	1,470
82	Clines Corners Wind Farm LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bq]26,677	20,925	20,925	25,577		0	25,577
83	CP Energy Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[br]1,000	1,458	1,458	14,899		0	14,899
84	DTE Energy Trading Inc	Not Available	Not Available	SFP	OATT	Various	Various	[bs]0					0	
85	Duran Mesa Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bs]13,755	18,430	18,430	112,413		[bh](467)	111,946
86	Dynasty Power Inc	Not Available	Not Available	SFP	OATT	Various	Various	[bt]3,953	7,904	7,904	51,494		[bi](792)	50,702
87	EDF Trading North America, LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bu]2,201	4,401	4,401	38,899		[bj](249)	38,650
88	El Cabo Wind	Not Available	Not Available	SFP	OATT	Various	Various	[bv]20			61		0	61
89	El Paso Electric Company	Not Available	Not Available	SFP	OATT	Various	Various	[bw]1	1	1	12		0	12
90	Exelon Generation Company, LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bx]400	896	896	6,464		[bk](17)	6,447
91	Grady Wind Energy Center-LLC	Not Available	Not Available	SFP	OATT	Various	Various	[by]0			[bl](103,582)		0	(103,582)
92	Guzman Power Markets LLC	Not Available	Not Available	SFP	OATT	Various	Various	[bz]8,336	28,454	28,454	240,248		[bl](960)	239,288
93	Guzman Renewable Energy Partners	Not Available	Not Available	SFP	OATT	Various	Various	[ca]8,143	17,509	17,509	132,354		[bm](614)	131,740
94	Imperial Irrigation District Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[cb]1,028	1,368	1,368	17,215		0	17,215
95	Los Angeles Wholesale Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[cc]14,282	14,441	14,441	172,036		[bn](147)	171,889
96	Macquarie Energy LLC	Not Available	Not Available	SFP	OATT	Various	Various	[cd]2,557	9,481	9,481	99,735		[bo](13)	99,722
97	Mag Energy Solutions, Inc	Not Available	Not Available	SFP	OATT	Various	Various	[ce]7,355	6,949	6,949	86,927		[bp](275)	86,652
98	Mercuria Energy America LLC	Not Available	Not Available	SFP	OATT	Various	Various	[cf]3,705	4,940	4,940	49,038		0	49,038
99	Morgan Stanley	Not Available	Not Available	SFP	OATT	Various	Various	[cg]2,693	2,648	2,648	20,067		0	20,067
100	Nevada Power Company	Not Available	Not Available	SFP	OATT	Various	Various	[ch]1,900	2,150	2,150	28,182		0	28,182
101	PacifiCorp	Not Available	Not Available	SFP	OATT	Various	Various	[ci]18,797	51,821	51,821	445,222		[bq](1,496)	443,726
102	Powerex	Not Available	Not Available	SFP	OATT	Various	Various	[cj]2,603	4,681	4,681	45,874		0	45,874
103	Public Service Company of New Mexico	Not Available	Not Available	SFP	OATT	Various	Various	[ck]17,115	40,049	40,049	274,533		[br](284)	274,249
104	Rainbow Energy Marketing	Not Available	Not Available	SFP	OATT	Various	Various	[cl]18,155	14,334	14,334	169,993		0	169,993
105	Red Cloud Wind Farm	Not Available	Not Available	SFP	OATT	Various	Various	[cm]22,546	16,284	16,284	109,050		0	109,050
106	Salt River Project	Not Available	Not Available	SFP	OATT	Various	Various	[cn]20,528	13,861	13,861	295,784		0	295,784
107	Shell Energy North America LP	Not Available	Not Available	SFP	OATT	Various	Various	[co]7,626	9,942	9,942	86,257		0	86,257
108	Southern California Edison Company	Not Available	Not Available	SFP	OATT	Various	Various	[cp]136	136	136	573		0	573
109	TEC Energy	Not Available	Not Available	SFP	OATT	Various	Various	[cq]200	200	200	2,027		0	2,027

110	Tecolote Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	[cz]17,651	22,421	22,421	43,793		0	43,793
111	Tenaska Power Services Co.	Not Available	Not Available	SFP	OATT	Various	Various	[cs]57,026	196,385	196,385	1,265,517		[bs](1,133)	1,264,384
112	The Energy Authority Inc.	Not Available	Not Available	SFP	OATT	Various	Various	[ct]3,867	4,879	4,879	35,232		[bt](5)	35,227
113	TransAlta Energy Marketing U.S. Inc.	Not Available	Not Available	SFP	OATT	Various	Various	[cu]8,608	17,614	17,614	140,551		[bu](204)	140,347
114	Tri-State Generation and Transmission Assoc, Inc.	Not Available	Not Available	SFP	OATT	Various	Various	[cv]1,635	1,200	1,200	8,852		[bv](3)	8,849
115	Tucson Electric Power Company	Not Available	Not Available	SFP	OATT	Various	Various	[cw]9,090	13,758	13,758	105,415		[bw](149)	105,266
116	UNIPER GLOBAL COMMODITIES NORTH AMERICA LLC	Not Available	Not Available	SFP	OATT	Various	Various	[cx]1,796	2,995	2,995	18,486		0	18,486
117	Western Area Power Administration (DSW)	Not Available	Not Available	SFP	OATT	Various	Various	[cy]17,262	32,545	32,545	187,437		[bx](1,041)	186,396
118	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	NF	OATT	Various	Various	[ce]14	336	336	1,690		0	1,690
119	Arizona Public Service Company	Not Available	Not Available	NF	OATT	Various	Various	[da]29	696	696	3,404		0	3,404
120	Guzman Power Markets LLC	Not Available	Not Available	NF	OATT	Various	Various	[db]25	560	560	2,534		0	2,534
121	Macquarie Energy LLC	Not Available	Not Available	NF	OATT	Various	Various	[dc]225	4,454	4,454	38,263		[bv](176)	38,087
122	Mercuria Energy America LLC	Not Available	Not Available	NF	OATT	Various	Various	[dd]35	934	934	4,161		0	4,161
123	Morgan Stanley	Not Available	Not Available	NF	OATT	Various	Various	[de]50	700	700	6,036		0	6,036
124	NOVO BioPower LLC	Not Available	Not Available	NF	OATT	Various	Various	[dc]10	231	231	1,235		0	1,235
125	PacifiCorp	Not Available	Not Available	NF	OATT	Various	Various	[dg]175			17,738		0	17,738
126	Southern California Edison Company	Not Available	Not Available	NF	OATT	Various	Various	[dh]238	4,659	4,659	28,187		0	28,187
127	Tecolote Wind LLC	Not Available	Not Available	NF	OATT	Various	Various	[di]8	156	156	811		0	811
128	Tenaska Power Services Co.	Not Available	Not Available	NF	OATT	Various	Various	[dj]150	2,520	2,520	20,322		0	20,322
129	UNIPER GLOBAL COMMODITIES NORTH AMERICA LLC	Not Available	Not Available	NF	OATT	Various	Various	[dk]421	3,621	3,621	73,993		0	73,993
130	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	NF	OATT	Various	Various	[dl]24	7,008	7,008	29,797		0	29,797
131	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	NF	OATT	Various	Various	[dm]272	272	272	1,690		0	1,690
132	Arizona Public Service Company	Not Available	Not Available	NF	OATT	Various	Various	[dn]220	65	65	1,658		[bz](11)	1,647
133	Avangrid Renewables, LLC	Not Available	Not Available	NF	OATT	Various	Various	[do]675	550	550	7,598		[ca]10	7,608
134	Black Hills Colorado Electric	Not Available	Not Available	NF	OATT	Various	Various	[dp]883	2,651	2,651	10,016		[cb](17)	9,999
135	Black Hills Power Inc	Not Available	Not Available	NF	OATT	Various	Various	[dq]1,305	1,820	1,820	10,294		[cc](5)	10,289
136	BP Energy Company	Not Available	Not Available	NF	OATT	Various	Various	[dr]60	100	100	621		[cd](1)	620
137	Broadview Energy KW- LLC	Not Available	Not Available	NF	OATT	Various	Various	[ds]71	71	71	2		[ce]16,098	16,100
138	Brookfield Energy Marketing LP	Not Available	Not Available	NF	OATT	Various	Various	[dt]0					0	
139	Brookfield Renewable Trading and Marketing LP	Not Available	Not Available	NF	OATT	Various	Various	[du]41	40	40	309		[cf](34)	275

140	Clines Corners Wind Farm LLC	Not Available	Not Available	NF	OATT	Various	Various	[dv]2,876	754	754	53,302		[ds](399)	52,903
141	ConocoPhillips- Inc.	Not Available	Not Available	NF	OATT	Various	Various	[dw]326	593	593	4,363		[dt](2)	4,361
142	CP Energy Marketing	Not Available	Not Available	NF	OATT	Various	Various	[dx]45	31	31	299		0	299
143	DTE Energy Trading Inc	Not Available	Not Available	NF	OATT	Various	Various	[dy]1,404	327	327	1,887		[du](4)	1,883
144	Duran Mesa Wind LLC	Not Available	Not Available	NF	OATT	Various	Various	[dz]400	301	301	10,217		0	10,217
145	Dynasty Power Inc	Not Available	Not Available	NF	OATT	Various	Various	[ea]6,915	12,040	12,040	83,677		[dv](133)	83,544
146	EDF Trading North America, LLC	Not Available	Not Available	NF	OATT	Various	Various	[eb]425	1,093	1,093	9,297		[dw](10)	9,287
147	El Paso Electric Company	Not Available	Not Available	NF	OATT	Various	Various	[ec]0					0	
148	Exelon Generation Company, LLC	Not Available	Not Available	NF	OATT	Various	Various	[ed]633	930	930	6,022		[dx](6)	6,016
149	Guzman Power Markets LLC	Not Available	Not Available	NF	OATT	Various	Various	[ee]5,366	14,521	14,521	142,923		[dy](109)	142,814
150	Guzman Renewable Energy Partners	Not Available	Not Available	NF	OATT	Various	Various	[ef]1,044	4,947	4,947	34,541		[dz](131)	34,410
151	Imperial Irrigation District Marketing	Not Available	Not Available	NF	OATT	Various	Various	[eg]900	727	727	3,791		[ea](190)	3,601
152	Macquarie Energy LLC	Not Available	Not Available	NF	OATT	Various	Various	[eh]5,575	10,999	10,999	91,145		[eb](56)	91,089
153	Mag Energy Solutions, Inc	Not Available	Not Available	NF	OATT	Various	Various	[ei]10,610	23,973	23,973	204,996		[ec](327)	204,669
154	Mercuria Energy America LLC	Not Available	Not Available	NF	OATT	Various	Various	[ej]3,104	6,847	6,847	59,045		[ed](605)	58,440
155	Morgan Stanley	Not Available	Not Available	NF	OATT	Various	Various	[ek]2,282	3,940	3,940	35,328		[ee](590)	34,738
156	Nevada Power Company	Not Available	Not Available	NF	OATT	Various	Various	[el]1,050	1,216	1,216	8,828		[ef](67)	8,761
157	PacifiCorp	Not Available	Not Available	NF	OATT	Various	Various	[em]2,310	5,047	5,047	27,843		[eg](770)	27,073
158	Powerex	Not Available	Not Available	NF	OATT	Various	Various	[en]1,383	1,579	1,579	19,070		[eh](1,884)	17,186
159	Public Service Company of Colorado	Not Available	Not Available	NF	OATT	Various	Various	[eo]650	650	650	4,900		[ei](12)	4,888
160	Public Service Company of New Mexico	Not Available	Not Available	NF	OATT	Various	Various	[ep]7,172	9,842	9,842	63,319		[ej]16,170	79,489
161	Rainbow Energy Marketing	Not Available	Not Available	NF	OATT	Various	Various	[eq]3,723	7,120	7,120	49,682		[ek](396)	49,286
162	Red Cloud Wind Farm	Not Available	Not Available	NF	OATT	Various	Various	[er]1,238	472	472	7,679		0	7,679
163	Salt River Project	Not Available	Not Available	NF	OATT	Various	Various	[es]1,745	21,179	21,179	22,978		[el]23,411	46,389
164	Sempra Gas & Power Marketing, LLC	Not Available	Not Available	NF	OATT	Various	Various	[et]406			3,060		0	3,060
165	Shell Energy North America LP	Not Available	Not Available	NF	OATT	Various	Various	[eu]2,955	7,311	7,311	78,622		[em](717)	77,905
166	Southern California Edison Company	Not Available	Not Available	NF	OATT	Various	Various	[ev]28	28	28	118		[en](551)	(433)
167	TEC Energy	Not Available	Not Available	NF	OATT	Various	Various	[ew]820	1,514	1,514	17,966		[eo](14)	17,952
168	Tecolote Wind LLC	Not Available	Not Available	NF	OATT	Various	Various	[ex]881	448	448	6,102		[ep]223,834	229,936
169	Tenaska Power Services Co.	Not Available	Not Available	NF	OATT	Various	Various	[ey]3,715	15,996	15,996	102,589		[eq]841	103,430
170	The Energy Authority Inc.	Not Available	Not Available	NF	OATT	Various	Various	[ez]3,735	13,091	13,091	101,651		[er](442)	101,209
171	TransAlta Energy Marketing U.S. Inc.	Not Available	Not Available	NF	OATT	Various	Various	[fa]8,207	38,719	38,719	269,674		[es](729)	268,945

172	Tri-State Generation and Transmission Assoc, Inc.	Not Available	Not Available	NF	OATT	Various	Various	(fb)20			88		(fb)(4)	84
173	Tucson Electric Power Company	Not Available	Not Available	NF	OATT	Various	Various	(fc)7,505	42,715	42,715	132,373		(fi)26,518	158,891
174	UNIPER GLOBAL COMMODITIES NORTH AMERICA LLC	Not Available	Not Available	NF	OATT	Various	Various	(fd)2,081	2,013	2,013	11,114		(fj)(21)	11,093
175	WestConnect	Not Available	Not Available	NF	OATT	Various	Various	(fe)0	300,092	300,092	1,103,188		0	1,103,188
176	Yuma Cogeneration Associates	Not Available	Not Available	NF	OATT	Various	Various	(ff)496	278	278	9,099		(fk)379	9,478
177	Arizona Public Service Company	Not Available	Not Available	OLF	RS 183	N/A	N/A	(fa)0	6,903,400	6,903,400			0	
178	PacifiCorp	Not Available	Not Available	OLF	RS 183	N/A	N/A	(fa)0	2,287,213	2,287,213			0	
179	Public Service Company of New Mexico	Not Available	Not Available	OLF	RS 73	Palo Verde	Four Corners	130	825,441	825,441	1,415,030		0	1,415,030
180	Yuma Cogeneration Associates	Yuma Cogeneration Assoc.	San Diego Gas and Elect.	OLF	RS 198	Riverside Substation	North Gila Sub	51	49,885	49,885	1,926,893		0	1,926,893
181	Imperial Irrigation District	Not Available	Not Available	OS	OATT	N/A	N/A	0					(fl)52,997	52,997
182	Luke AFB Main Field	DOE WAPA Lower	Luke Air Force Base	OS	RS 162	Pinnacle Peak Sub	Luke Substation	(fl)0			173,448	1,033	0	174,481
183	Marine Corps. Air Station	DOE WAPA Lower	Marine Corps Air Station	OS	RS 166	Gila Substation	Marine Corps Air Stn	(fl)0			77,652		0	77,652
184	NOVO BioPower LLC	Not Available	Not Available	OS	OATT	N/A	N/A	0					(fm)2,716	2,716
185	Salt River Project (Schedule F)	Not Available	Not Available	OS	RS 3	N/A	N/A	(fk)0			12,977		0	12,977
186	Salt River Project (Schedule Q)	Pinnacle Peak	Ocotillo 230	OS	RS 3	Pinnacle Peak	Ocotillo 230	0					(fn)935,984	935,984
187	Unit B Irrigation and Drainage District	Not Available	Not Available	OS	RS 181	Gila Substation	District Customer	(fl)0			540		0	540
188	Yuma Mesa Irrigation and Drainage District	DOE WAPA Lower	Yuma-Mesa Irrigation Dist	OS	RS 31	Gila Substation	Yuma Mesa Load	(fm)0			4,500		0	4,500
189	Navajo Transitional Energy Company, LLC	Not Available	Not Available	OS	RS 291	N/A	N/A	0				430,122	(fo)31,104	461,226
190	Other	Not Available	Not Available	AD	Not Available	Not Available	Not Available	0					(fp)(2,133,686)	(2,133,686)
35	TOTAL							454,551	45,638,989	45,638,989	92,116,941	765,901	6,522,988	99,405,830

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Service to Arizona Public Service Company pursuant to Part III of the OATT

(b) Concept: PaymentByCompanyOrPublicAuthority

Service to Arizona Public Service Company pursuant to Part III of the OATT

(c) Concept: PaymentByCompanyOrPublicAuthority

Service to Arizona Public Service Company pursuant to Part III of the OATT

(d) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Service to Arizona Public Service Company pursuant to Part III of the OATT

(e) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Service to Arizona Public Service Company pursuant to Part III of the OATT

(f) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Service to Arizona Public Service Company pursuant to Part III of the OATT

(g) Concept: BillingDemand

Service to Arizona Public Service Company pursuant to Part III of the OATT

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(en) Concept: BillingDemand
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(eo) Concept: BillingDemand
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(ep) Concept: BillingDemand
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Hourly Demand Service Period
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(fd) Concept: BillingDemand
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(fe) Concept: BillingDemand
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(ff) Concept: BillingDemand
Hourly Demand Service Period
(fg) Concept: BillingDemand
Exchange agreement pursuant to Pre888 contract
(fh) Concept: BillingDemand
Exchange agreement pursuant to Pre888 contract
(fi) Concept: BillingDemand
Part of APS NITS load - recovery of transmission cost contract
(fj) Concept: BillingDemand
Part of APS NITS load - recovery of transmission cost contract
(fk) Concept: BillingDemand
Part of APS NITS load - recovery of transmission cost contract
(fl) Concept: BillingDemand
Part of APS NITS load - recovery of transmission cost contract
(fm) Concept: BillingDemand
Part of APS NITS load - recovery of transmission cost contract
(fn) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Resale Credits
(fo) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Resale Credits
(fp) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Resale Credits
(fq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
AzISA Fees and Unreserved Use Penalty/Credit
(fr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Service to Arizona Public Service Company pursuant to Part III of the OATT
(fs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Service to Arizona Public Service Company pursuant to Part III of the OATT
(ft) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Credit
(fu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Credit
(fv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Credit
(fw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Unreserved Use Credit
(fx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(fy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(fz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ga) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(gb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(gg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(gh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Penalty/Credit
(gi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(gj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(gk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Charge equivalent to SFP monthly charge for long-term transmission contract deferral, recognized over deferral period
(gl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Charge equivalent to SFP monthly charge for long-term transmission contract deferral, recognized over deferral period
(gm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Charge equivalent to SFP monthly charge for long-term transmission contract deferral, recognized over deferral period
(gn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(go) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ie) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(if) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ig) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(ih) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ii) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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Unreserved Use Credit

(iw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ix) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(iy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(jc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(jd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(je) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(jf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(jg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ji) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(jj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(jk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(jl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges
(jm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges
(jn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges
(jo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
BA Services Administrative Fees
(jp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
FERC Transmission rate true up, change in estimate, and timing difference

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	[a] Arizona Public Service Co	LFP			121,540			121,540
2	Bureau of Indian Affairs	[b] OLF			153,600			153,600
3	Department of Energy	[c] OS	607,725	607,725		874,890	[c](30,697)	844,193
4	Department of Energy	NF	287,016	287,016	730,761	247,261	[c](28,221)	949,801
5	Department of Energy	FNS	364,228	364,228	1,330,165	637,288	[c]18,145	1,985,598
6	Department of Energy	FNS	1,173,399	1,173,399	5,068,047	1,932,567	[c](17,900)	6,982,714
7	Department of Energy	[d] LFP	397,834	397,834		710,789	[d]55,068	765,857
8	Department of Energy	[e] LFP	371,001	371,001	8,832,714	777,996	[c](8,163)	9,602,547
9	Department of Energy	[f] OS			146,112		[c](53,285)	92,827
10	Electric District # 3	LFP	2,916	2,916	96,030		[c]94	96,124
11	Electric District # 4	[g] OLF	2,351	2,351	70,768		[g]121	70,889
12	Salt River Project	[h] FNS	33,670	33,670	180,372	63,774	[c](55,044)	189,102
13	Salt River Project	[i] OLF	342,523	342,523	1,556,556	621,352	[w](621,352)	1,556,556
14	Salt River Project	[j] LFP	156,221	156,221	2,115,000	232,053	[z](400,006)	1,947,047
15	Salt River Project	FNS	457,121	457,121	3,125,351	887,813	[aa](520,988)	[ak]3,492,176
16	Salt River Project	[k] OLF	125,594	125,594	275,069	230,005	[ab](230,005)	275,069
17	Salt River Project	[l] OS	1,584,214	1,584,214		819,745	[ac]819,427	1,639,172
18	Salt River Project	FNS	194,217	194,217	2,965,816	701,207	[ad](727,194)	2,939,829
19	Southern California Edison	[m] LFP	110	110	198,570		[ae]5,259	203,829

20	Southwest Transmission Cooperative Inc.	SFP	66,514	66,514	309,435	14,841	[af](161,305)	162,971
21	Tucson Electric Power	NF	3,385	3,385	24,430	532	[aa]1,437	26,399
22	Public Service Company of New Mexico	NF	3,290	3,290	29,421	318	[ab]47	29,786
23	SRP Misc Accounts Receivable	OS	5,887	5,887	20,195	11,842	[ac]796	32,833
24	Navopache Electric Cooperative	[q] OS			322,752			322,752
25	Navopache Electric Cooperative	OS	17,410	17,410		1,302,527	[z](104,523)	1,198,004
	TOTAL		6,196,626	6,196,626	27,672,704	10,066,800	(2,058,289)	35,681,215

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Intercompany Transmission

(b) Concept: StatisticalClassificationCode

Terminates with 30 days notice

(c) Concept: StatisticalClassificationCode

Loss compensation on jointly owned facilities

(d) Concept: StatisticalClassificationCode

Terminates September 30, 2029

(e) Concept: StatisticalClassificationCode

Terminates December 31, 2022

(f) Concept: StatisticalClassificationCode

Terminates September 30, 2029

(g) Concept: StatisticalClassificationCode

Effective until terminated by counterparty

(h) Concept: StatisticalClassificationCode

Terminates January 1, 2024

(i) Concept: StatisticalClassificationCode

Terminates with 5 year notice

(j) Concept: StatisticalClassificationCode

Terminates May 1, 2023

(k) Concept: StatisticalClassificationCode

Terminates with 1 year notice

(l) Concept: StatisticalClassificationCode

Loss compensation for deliveries to DV

(m) Concept: StatisticalClassificationCode

Terminates September 30, 2037

(n) Concept: StatisticalClassificationCode

Navopache Vernon Tie Facilities use charges

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(q) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(r) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(s) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(t) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(u) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(v) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(w) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(x) Concept: OtherChargesTransmissionOfElectricityByOthers

Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.

(y) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing
(z) Concept: OtherChargesTransmissionOfElectricityByOthers
Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.
(aa) Concept: OtherChargesTransmissionOfElectricityByOthers
Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.
(ab) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ac) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ad) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ae) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary/Timing
(af) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ag) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ah) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ai) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(aj) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ak) Concept: ChargesForTransmissionOfElectricityByOthers
APS payment as a credit on APS provides SRP in the same contract

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,101,385
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Allocation of Parent Company Costs	5,812,328
7	Bank Fees	1,379,221
8	Billed to Others-Services Performed	(84,289,495)
9	Communication Service	754,564
10	Materials & Supplies	1,062,057
11	Payroll	7,206,603
12	Outside Services	7,137,806
13	Rents/Leases	785,645
14	Transportation Expense	7,503
15	Travel	305,096
16	Other Expenses	(305,008)
46	TOTAL	(59,042,295)

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			81,098,793		81,098,793
2	Steam Production Plant	84,441,180	5,527,974	3,553		89,972,707
3	Nuclear Production Plant	29,255,106	(752,287)	4,358,995		32,861,814
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	129,789,070	1,105,476			130,894,546
7	Transmission Plant	61,773,847		7,483,616		69,257,463
8	Distribution Plant	165,994,243		1,373,729		167,367,972
9	Regional Transmission and Market Operation					
10	General Plant	65,057,334		8,311,304		73,368,638
11	Common Plant-Electric					
12	TOTAL	536,310,780	5,881,163	102,629,990		644,821,933

B. Basis for Amortization Charges

[a]
See Footnote

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13	311	232.625	23 years	(850)	621	O1	11 years
14	312	1,540.532	24 years	(1,060)	485	O1	15 years
15	314	226.276	24 years	(990)	533	O1	13 years
16	315	134.337	27 years	(900)	531	O1	13 years
17	316	104.646	24 years	(970)	498	O1	14 years
18	NUCLEAR PRODUCTION						

19	321	884.363	45 years	(40)	61	O1	27 years
20	322	1,251.01	46 years	(100)	6	O1	26 years
21	323	428.057	43 years	(30)	68	O1	26 years
22	324	303.682	50 years	(40)	(35)	O1	26 years
23	325	251.184	39 years	(40)	125	O1	27 years
24	OTHER PRODUCTION						
25	341	278.15	28 years	(670)	398	O1	20 years
26	342	66.438	27 years	(500)	412	O1	14 years
27	343	1,086.016	29 years	(500)	380	O1	17 years
28	344	1,762.069	29 years	(710)	371	O1	24 years
29	345	305.832	29 years	(820)	381	O1	21 years
30	346	94.376	23 years	(530)	484	O1	16 years
31	TRANSMISSION						
32	352	227.611	50 years		184	R4	36 years
33	353	1,385.885	45 years	(500)	214	S0.5	36 years
34	354	191.882	60 years		134	R3	33 years
35	355.1	79.91	50 years	(2,000)	221	R1	38 years
36	355.2	655.639	55 years	(2,000)	210	R1.5	48 years
37	356	543.419	60 years	(2,000)	187	R3	45 years
38	357	32.422	60 years		155	R4	45 years
39	358	57.11	60 years	1,500	133	L1.5	47 years
40	DISTRIBUTION						
41	361	114.673	60 years	(1,000)	178	R3	47 years
42	362	836.433	45 years	(500)	225	L0.5	37 years
43	363	1.903	10 years		1,006	S3	9 years
44	364.1	413.1	45 years	(2,000)	259	L0	35 years
45	364.2	433.601	50 years	(1,000)	216	R0.5	44 years
46	365	449.197	50 years	(2,000)	236	O1	43 years

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: BasisAmortizationCharges

RATES		
Franchises	302	—
Software	303	10.00% to 33.33%
Misc. Intangibles	303	2.00% to 20.00%
Limited Term Land Rights	310350360389	1.67% to 50.00%
Office Equipment & Furniture, Small Tools, Garage Equipment, Misc. Equipment	391,391.2,393,394,395,398	4.17% to 5.00%
Leasehold Improvements	321,322,323,324,325,326,371,390,397	amortized over the life of the lease

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	ACC/Residential Utility Consumer Office Expenses					—	—					
2	Annual Assessment by Arizona Corporation					—	—					
3	Commission (ACC) and Annual Assessment by					—	—					
4	Residential Utility Commission (RUCO)	7,767,156		7,767,156		Electric	928	7,767,156				
5	Legal and Filing Fees		1,461,663	1,461,663		Electric	928	1,461,663				
6	Consulting fees		245,266	245,266		Electric	928	245,266				
7	Payroll and Employee expenses		2,745,534	2,745,534		Electric	928	2,745,534				
8	Est. ACC and RUCO assessments on Unbilled Rev	2,294		2,294		Electric	928	2,294				
9	Other		30	30		Electric	928	30				
10						—	—					
11	FERC Expenses					—	—					
12	Regulatory Assessment by FERC	4,538,000		4,538,000		Electric	928	4,538,000				
13	Legal and Filing Fees						—					
14	Consulting fees					—	—					
15	Payroll and Employee expenses					—	—					
16	Other					—	—					
18	Nuclear Regulatory Commission Expenses					—	—					
19	NRC License FEE	5,335,480		5,335,480		Electric	928	5,335,480				
46	TOTAL	17,642,930	4,452,493	22,095,423				22,095,423				

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   Electric R, D and D Performed Internally:

   Generation

   hydroelectric

   Recreation fish and wildlife
   Other hydroelectric

   Fossil-fuel steam
   Internal combustion or gas turbine
   Nuclear
   Unconventional generation
   Siting and heat rejection

   Transmission

   Overhead
   Underground

   Distribution
   Regional Transmission and Market Operation
   Environment (other than equipment)
   Other (Classify and include items in excess of $50,000.)
   Total Cost Incurred

   Electric, R, D and D Performed Externally:

   Research Support to the electrical Research Council or the Electric Power Research Institute
   Research Support to Edison Electric Institute
   Research Support to Nuclear Power Groups
   Research Support to Others (Classify)
   Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	B(1)	EPRI		249,579	165	249,579	
2	B(1)	EPRI		(8,897)	236	(8,897)	
3	B(1)	EPRI		394,796	500	394,796	
4	B(1)	EPRI		78,084	506	78,084	
5	B(1)	EPRI		805,127	524	805,127	
6	B(1)	EPRI		9,603	528	9,603	
7	B(1)	EPRI		12,804	530	12,804	
8	B(1)	EPRI		71,839	546	71,839	
9	B(1)	EPRI		478,212	549	478,212	
10	B(1)	EPRI		1,080,895	580	1,080,895	
11	B(1)	EPRI		175,056	588	175,056	
12	B(1)	EPRI		115,572	908	115,572	
13	B(1)	EPRI		166,933	920	166,933	
14	Total			3,629,603		3,629,603	

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	126,321,270		
4	Transmission	19,841,658		
5	Regional Market	280,619		
6	Distribution	43,071,474		
7	Customer Accounts	23,199,992		
8	Customer Service and Informational	2,375,067		
9	Sales	8,148,588		
10	Administrative and General	120,181,323		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	343,419,991		
12	Maintenance			
13	Production	40,895,844		
14	Transmission	3,314,765		
15	Regional Market			
16	Distribution	17,100,013		
17	Administrative and General	3,701,620		
18	TOTAL Maintenance (Total of lines 13 thru 17)	65,012,242		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	167,217,115		
21	Transmission (Enter Total of lines 4 and 14)	23,156,423		
22	Regional Market (Enter Total of Lines 5 and 15)	280,619		
23	Distribution (Enter Total of lines 6 and 16)	60,171,487		
24	Customer Accounts (Transcribe from line 7)	23,199,992		
25	Customer Service and Informational (Transcribe from line 8)	2,375,067		
26	Sales (Transcribe from line 9)	8,148,588		
27	Administrative and General (Enter Total of lines 10 and 17)	123,882,942		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	408,432,233		408,432,233
29	Gas			

30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
59	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
37	Customer Accounts (Line 37)			
38	Customer Service and Informational (Line 38)			
39	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	408,432,233		408,432,233
66	Utility Plant			

67	Construction (By Utility Departments)			
68	Electric Plant	199,012,165		199,012,165
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	199,012,165		199,012,165
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Inventory	6,721,062		6,721,062
80	Deferred Debits	(118,345)		(118,345)
81	Other Revenue	89,095		89,095
82	Other Income			
83	Miscellaneous Income Deductions	3,797,158		3,797,158
84	Misc. Deferred Debit Reconciling Items	788,125		788,125
85	Palo Verde Generating Station	199,858,329		199,858,329
86	Four Corners	15,887,427		15,887,427
87	Cholla-Pacificorp	44,116		44,116
88	Yucca	1,891,892		1,891,892
89	Four Corners 230/345			
90	Morgan Pinnacle Peak	309,365		309,365
91	PV-NG Yuma	116,709		116,709
92	Navajo STS 500 KV Line	1,393,765		1,393,765
93	Saguaro	32,955		32,955
94	Studies/Streetlights	551,680		551,680
95	Miscellaneous Billings	1,507,521		1,507,521
95	TOTAL Other Accounts	232,870,852		232,870,852
96	TOTAL SALARIES AND WAGES	840,315,250		840,315,250

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	12,519,220	22,974,402	33,082,621	41,494,426
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(12,197,365)	(20,641,165)	(63,840,408)	(74,940,830)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	CAISO Non Purchases (Account 555)	2,199,497	3,424,877	4,611,174	5,680,860
46	TOTAL	2,521,352	5,758,114	(26,146,613)	(27,765,544)

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]62,180	MW	1,730,006	[b]79,996	MW	2,288,159
2	Reactive Supply and Voltage	62,180	MW		80,698	MW	
3	Regulation and Frequency Response	62,180	MW	6,716,922	65,181	MW	6,960,016
4	Energy Imbalance		MWh		(4,594)	MWh	(2,609,643)
5	Operating Reserve - Spinning	62,180	MW	15,537,191	64,587	MW	15,978,304
6	Operating Reserve - Supplement	62,180	MW	1,964,991	64,587	MW	1,998,034
7	Other		MWh			MWh	
8	Total (Lines 1 thru 7)	310,900		25,949,110	350,455		24,614,870

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

Short-term demand excluded due to mismatch of demand measurement (Hourly, Daily, etc.). Short-term service accounts for $832.07 purchased in column (d) for 2021.

(b) Concept: AncillaryServicesSoldNumberOfUnits

Short-term demand excluded due to mismatch of demand measurement (Hourly, Daily, etc.). Short-term service accounts for $161,754.61 of sold revenue in column (g) for 2021.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: Arizona Public Service Company									
1	January	5,857	27	8	4,250	140	1,286	181		
2	February	5,339	19	8	3,690	182	1,286	181		
3	March	5,363	1	8	3,707	189	1,286	181		
4	Total for Quarter 1				11,647	511	3,858	543		
5	April	6,036	30	18	4,378	191	1,286	181		
6	May	6,829	31	18	5,142	220	1,286	181		
7	June	9,270	18	18	7,534	269	1,286	181		
8	Total for Quarter 2				17,054	680	3,858	543		
9	July	8,902	8	18	7,189	246	1,286	181		
10	August	9,002	4	18	7,313	222	1,286	181		
11	September	8,278	9	17	6,587	224	1,286	181		
12	Total for Quarter 3				21,089	692	3,858	543		
13	October	6,319	3	18	4,678	174	1,286	181		
14	November	5,385	4	18	3,754	164	1,286	181		
15	December	5,888	16	8	3,958	160	1,589	181		
16	Total for Quarter 4				12,390	498	4,161	543		
17	Total				62,180	2,381	15,735	2,172		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Arizona Public Service Company									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-03-16	Year/Period of Report End of: 2021/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	29,228,236
3	Steam	13,424,898	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear	9,204,276	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,850,839
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	62,532
7	Other	3,664,015	27	Total Energy Losses	1,781,397
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	26,293,189	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	34,923,004
10	Purchases (other than for Energy Storage)	8,841,581			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	211,766			
14	Net Exchanges (Line 12 minus line 13)	(211,766)			
15	Transmission For Other (Wheeling)				
16	Received	45,638,989			
17	Delivered	45,638,989			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	34,923,004			

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Arizona Public Service Company					
29	January	2,433,477	194,721	4,213	27	8
30	February	2,024,922	175,060	3,708	19	8
31	March	2,323,076	283,825	3,730	1	8
32	April	2,244,996	117,367	4,451	30	18
33	May	2,637,660	94,219	5,193	31	18
34	June	3,675,779	263,990	7,575	18	18
35	July	4,231,403	628,867	7,224	8	18
36	August	4,276,893	745,026	7,340	4	18
37	September	3,666,592	564,175	6,619	9	17
38	October	2,586,689	311,203	4,712	3	18
39	November	2,289,483	213,636	3,802	4	18
40	December	2,532,034	294,170	3,965	16	8
41	Total	34,923,004	3,886,259			

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants)

1. Report data for p ant n Serv ce on y.
2. Large p ants are steam p ants w th nsta ed capac ty (name p ate rat ng) of 25,000 Kw or more. Report n th s page gas turb ne and nterna combust on p ants of 10,000 Kw or more, and nuc ear p ants.
3. Ind cate by a footnote any p ant eased or operated as a jo nt fac ty.
4. If net peak demand for 60 m nutes s not ava ab e, g ve data wh ch s ava ab e, spec fy ng per od.
5. If any emp oyees attend more than one p ant, report on ne 11 the approx mate average number of emp oyees ass gnab e to each p ant.
6. If gas s used and purchased on a therm bas s report the Btu content or the gas and the quant ty of fue burned converted to Mct.
7. Quant t es of fue burned (L ne 38) and average cost per un t of fue burned (L ne 41) must be cons stent w th charges to expense accounts 501 and 547 (L ne 42) as show on L ne 20.
8. If more than one fue s burned n a p ant furn sh on y the compos te heat rate for a fue s burned.

Line No	tem (a)	Plant Name: Cholla 1 (b)			Plant Name: Cholla 3 (c)		
		Cholla 1 Steam			Cholla 3 Steam		
1	Kind of Plant (nternal Comb Gas Turb Nuclear	Steam			Steam		
2	Type of Constr (Conventional Outdoor Boiler etc)	More than 50% Outdoors			More than 50% Outdoors		
3	Year Originally Constructed	1905			1905		
4	Year Last Unit was nstalled	1905			1905		
5	Total nstalled Cap (Max Gen Name Plate Ratings-MW)	114			312		
6	Net Peak Demand on Plant - MW (60 minutes)	117			272		
7	Plant Hours Connected to Load	7 688			5 873		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	116			271		
10	When Limited by Condenser Water	116			271		
11	Average Number of Employees	40			66		
12	Net Generation Exclusive of Plant Use - KWh	684 476 392			1 200 770 284		
13	Cost of Plant Land and Land Rights	1 511 718			3 837 020		
14	Structures and mprovements	22 580 608			58 124 864		
15	Equipment Costs	152 992 908			408 355 349		
16	Asset Retirement Costs	18 567 805			27 166 838		
17	Total Cost	195 653 039			497 484 071		
18	Cost per KW of nstalled Capacity (line 17/5) ncluding	1 716			1 595		
19	Production Expenses Oper Supv & Engr	487 337			2 192 659		
20	Fuel	21 609 162			39 673 524		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	3 351 432			5 170 626		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	648 214			259 406		
26	Misc Steam (or Nuclear) Power Expenses	1 946 676			3 363 366		
27	Rents	0			0		
28	Allowances	783 089			1 373 765		
29	Maintenance Supervision and Engineering	1 389 695			2 057 748		
30	Maintenance of Structures	1 091 982			3 951 629		
31	Maintenance of Boiler (or reactor) Plant	2 378 779			4 612 425		
32	Maintenance of Electric Plant	270 266			1 584 966		
33	Maintenance of Misc Steam (or Nuclear) Plant	816 712			2 819 482		
34	Total Production Expenses	34 773 344			67 059 596		
35	Expenses per Net KWh	0 0508			0 0558		
36	Fuel Kind (Coal Gas Oil or Nuclear)	Coal	Oil	Gas	Coal	Oil	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	T	bbl	Mcf	T	bbl	Mcf
38	Quantity (Units) of Fuel Burned	258 113	0	634	649 247	3 487	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	26 646	0	862 776	9 303	129 472	0
40	Avg Cost of Fuel/unit as Delvd f o b during year	80	0	11	59	87	0
41	Average Cost of Fuel per Unit Burned	84	0	11	61	162	0
42	Average Cost of Fuel Burned per Million BTU	2	0	13	3	30	0
43	Average Cost of Fuel Burned per KWh Net Gen	0	0	0	0	0	0
44	Average BTU per KWh Net Generation	20 097	0	20 097	10 076	10 076	0

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants)

1. Report data for p ant n Serv ce on y.
2. Large p ants are steam p ants w th nsta ed capac ty (name p ate rat ng) of 25,000 Kw or more. Report n th s page gas turb ne and nterna combust on p ants of 10,000 Kw or more, and nuc ear p ants.
3. Ind cate by a footnote any p ant eased or operated as a jo nt fac ty.
4. If net peak demand for 60 m nutes s not ava ab e, g ve data wh ch s ava ab e, spec fy ng per od.
5. If any emp oyees attend more than one p ant, report on ne 11 the approx mate average number of emp oyees ass gnab e to each p ant.
6. If gas s used and purchased on a therm bas s report the Btu content or the gas and the quant ty of fue burned converted to Mct.
7. Quant t es of fue burned (L ne 38) and average cost per un t of fue burned (L ne 41) must be cons stent w th charges to expense accounts 501 and 547 (L ne 42) as show on L ne 20.
8. If more than one fue s burned n a p ant furn sh on y the compos te heat rate for a fue s burned.

Line No	tem (a)	Plant Name Yucca 2 (b)			Plant Name Yucca 3 (c)		
		Yucca 2 Comb Turbine			Yucca 3 Comb Turbine		
1	Kind of Plant (nternal Comb Gas Turb Nuclear	Comb Turbine			Comb Turbine		
2	Type of Constr (Conventional Outdoor Boiler etc)	More than 50% Outdoors			More than 50% Outdoors		
3	Year Originally Constructed	1905			1905		
4	Year Last Unit was nstalled	1905			1905		
5	Total nstalled Cap (Max Gen Name Plate Ratings-MW)	24			72		
6	Net Peak Demand on Plant - MW (60 minutes)	18			55		
7	Plant Hours Connected to Load	324			1 048		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	19			55		
10	When Limited by Condenser Water	19			55		
11	Average Number of Employees	0			3		
12	Net Generation Exclusive of Plant Use - KWh	3 053 000			26 622 000		
13	Cost of Plant Land and Land Rights	0			0		
14	Structures and mprovements	896 566			1 180 751		
15	Equipment Costs	6 856 253			35 934 115		
16	Asset Retirement Costs	0			0		
17	Total Cost	7 752 819			37 114 866		
18	Cost per KW of nstalled Capacity (line 17/5) ncluding	323			515		
19	Production Expenses Oper Supv & Engr	21 341			186 092		
20	Fuel	175 512			1 349 836		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	11 112			96 893		
26	Misc Steam (or Nuclear) Power Expenses	6 444			56 624		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	2 639			23 015		
30	Maintenance of Structures	1 192			14 221		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	82 910			523 814		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	301 150			2 250 495		
35	Expenses per Net KWh	0 0986			0 0845		
36	Fuel Kind (Coal Gas Oil or Nuclear)		Oil	Gas		Oil	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		bbl	Mcf		bbl	Mcf
38	Quantity (Units) of Fuel Burned		0	442 248		4 185	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		0	1 027 003		138 235	0
40	Avg Cost of Fuel/unit as Delvd f o b during year		0	3		75	0
41	Average Cost of Fuel per Unit Burned		0	3		182	0
42	Average Cost of Fuel Burned per Million BTU		0	3		31	0
43	Average Cost of Fuel Burned per KWh Net Gen		0	0		1	0
44	Average BTU per KWh Net Generation		0	17 061		21 240	0

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants)

1. Report data for p ant n Serv ce on y.
2. Large p ants are steam p ants w th nsta ed capac ty (name p ate rat ng) of 25,000 Kw or more. Report n th s page gas turb ne and nterna combust on p ants of 10,000 Kw or more, and nuc ear p ants.
3. Ind cate by a footnote any p ant eased or operated as a jo nt fac ty.
4. If net peak demand for 60 m nutes s not ava ab e, g ve data wh ch s ava ab e, spec fy ng per od.
5. If any emp oyees attend more than one p ant, report on ne 11 the approx mate average number of emp oyees ass gnab e to each p ant.
6. If gas s used and purchased on a therm bas s report the Btu content or the gas and the quant ty of fue burned converted to Mct.
7. Quant t es of fue burned (L ne 38) and average cost per un t of fue burned (L ne 41) must be cons stent w th charges to expense accounts 501 and 547 (L ne 42) as show on L ne 20.
8. If more than one fue s burned n a p ant furn sh on y the compos te heat rate for a fue s burned.

Line No	tem (a)	Plant Name Douglas (b)			Plant Name Saguaro 1 (c)		
		Douglas Comb Turbine			Saguaro 1 Comb Turbine		
1	Kind of Plant (nternal Comb Gas Turb Nuclear	Comb Turbine			Comb Turbine		
2	Type of Constr (Conventional Outdoor Boiler etc)	More than 50% Outdoors			More than 50% Outdoors		
3	Year Originally Constructed	1905			1905		
4	Year Last Unit was nstalled	1905			1905		
5	Total nstalled Cap (Max Gen Name Plate Ratings-MW)	26			53		
6	Net Peak Demand on Plant - MW (60 minutes)	12			54		
7	Plant Hours Connected to Load	17			288		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	16			55		
10	When Limited by Condenser Water	16			55		
11	Average Number of Employees	0			1		
12	Net Generation Exclusive of Plant Use - KWh	62 000			8 233 000		
13	Cost of Plant Land and Land Rights	9 557			15 230		
14	Structures and mprovements	103 952			3 062 107		
15	Equipment Costs	5 751 529			26 427 477		
16	Asset Retirement Costs	0			0		
17	Total Cost	5 865 038			29 504 814		
18	Cost per KW of nstalled Capacity (line 17/5) ncluding	226			557		
19	Production Expenses Oper Supv & Engr	0			0		
20	Fuel	16 562			563 540		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	1 644			14 167		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	6			773		
30	Maintenance of Structures	6 907			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	191 852			305 653		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			3 783		
34	Total Production Expenses	216 971			887 916		
35	Expenses per Net KWh	3 4995			0 1078		
36	Fuel Kind (Coal Gas Oil or Nuclear)		Oil				Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		bbl				Mcf
38	Quantity (Units) of Fuel Burned		184				160 098
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		132 512				1 040 007
40	Avg Cost of Fuel/unit as Delvd f o b during year		90				4
41	Average Cost of Fuel per Unit Burned		90				4
42	Average Cost of Fuel Burned per Million BTU		16				3
43	Average Cost of Fuel Burned per KWh Net Gen		0				0
44	Average BTU per KWh Net Generation		16 476				20 224

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants)

1. Report data for p ant n Serv ce on y.
2. Large p ants are steam p ants w th nsta ed capac ty (name p ate rat ng) of 25,000 Kw or more. Report n th s page gas turb ne and nterna combust on p ants of 10,000 Kw or more, and nuc ear p ants.
3. Ind cate by a footnote any p ant eased or operated as a jo nt fac ty.
4. If net peak demand for 60 m nutes s not ava ab e, g ve data wh ch s ava ab e, spec fy ng per od.
5. If any emp oyees attend more than one p ant, report on ne 11 the approx mate average number of emp oyees ass gnab e to each p ant.
6. If gas s used and purchased on a therm bas s report the Btu content or the gas and the quant ty of fue burned converted to Mct.
7. Quant t es of fue burned (L ne 38) and average cost per un t of fue burned (L ne 41) must be cons stent w th charges to expense accounts 501 and 547 (L ne 42) as show on L ne 20.
8. If more than one fue s burned n a p ant furn sh on y the compos te heat rate for a fue s burned.

Line No	tem (a)	Plant Name: Ocotillo 2 (b)	Plant Name: Ocotillo 3 (c)
		Ocotillo 2 Comb Turbine	Ocotillo 3 Comb Turbine
1	Kind of Plant (nternal Comb Gas Turb Nuclear	Comb Turbine	Comb Turbine
2	Type of Constr (Conventional Outdoor Boiler etc)	More than 50% Outdoors	More than 50% Outdoors
3	Year Originally Constructed	1905	1905
4	Year Last Unit was nstalled	1905	1905
5	Total nstalled Cap (Max Gen Name Plate Ratings-MW)	53	140
6	Net Peak Demand on Plant - MW (60 minutes)	55	107
7	Plant Hours Connected to Load	182	2 001
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	55	102
10	When Limited by Condenser Water	55	102
11	Average Number of Employees	3	5
12	Net Generation Exclusive of Plant Use - KWh	5 535 710	146 992 870
13	Cost of Plant Land and Land Rights	137 874	0
14	Structures and mprovements	5 034 017	19 140 006
15	Equipment Costs	28 951 803	91 567 362
16	Asset Retirement Costs	0	0
17	Total Cost	34 123 694	110 707 368
18	Cost per KW of nstalled Capacity (line 17/5) ncluding	644	791
19	Production Expenses Oper Supv & Engr	24 299	645 238
20	Fuel	231 386	6 436 195
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	16 183	429 714
26	Misc Steam (or Nuclear) Power Expenses	7 502	199 209
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	3 838	101 901
30	Maintenance of Structures	12 192	264 712
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	214 813	708 954
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	510 213	8 785 923
35	Expenses per Net KWh	0 0922	0 0598
36	Fuel Kind (Coal Gas Oil or Nuclear)	Gas	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	268 674	4 152 140
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1 034 990	1 035 000
40	Avg Cost of Fuel/unit as Delvd f o b during year	1	2
41	Average Cost of Fuel per Unit Burned	1	2
42	Average Cost of Fuel Burned per Million BTU	1	2
43	Average Cost of Fuel Burned per KWh Net Gen	0	0
44	Average BTU per KWh Net Generation	50 233	29 236

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants)

1. Report data for p ant n Serv ce on y.
2. Large p ants are steam p ants w th nsta ed capac ty (name p ate rat ng) of 25,000 Kw or more. Report n th s page gas turb ne and nterna combust on p ants of 10,000 Kw or more, and nuc ear p ants.
3. Ind cate by a footnote any p ant eased or operated as a jo nt fac ty.
4. If net peak demand for 60 m nutes s not ava ab e, g ve data wh ch s ava ab e, spec fy ng per od.
5. If any emp oyees attend more than one p ant, report on ne 11 the approx mate average number of emp oyees ass gnab e to each p ant.
6. If gas s used and purchased on a therm bas s report the Btu content or the gas and the quant ty of fue burned converted to Mct.
7. Quant t es of fue burned (L ne 38) and average cost per un t of fue burned (L ne 41) must be cons stent w th charges to expense accounts 501 and 547 (L ne 42) as show on L ne 20.
8. If more than one fue s burned n a p ant furn sh on y the compos te heat rate for a fue s burned.

Line No	tem (a)	Plant Name: Ocotillo 7 (b)	Plant Name: West Phoenix 1 (c)
		Ocotillo 7 Comb Turbine	West Phoenix 1 Comb Turbine
1	Kind of Plant (nternal Comb Gas Turb Nuclear	Comb Turbine	Comb Turbine
2	Type of Constr (Conventional Outdoor Boiler etc)	More than 50% Outdoors	More than 50% Outdoors
3	Year Originally Constructed	1905	1905
4	Year Last Unit was nstalled	1905	1905
5	Total nstalled Cap (Max Gen Name Plate Ratings-MW)	140	53
6	Net Peak Demand on Plant - MW (60 minutes)	104	49
7	Plant Hours Connected to Load	1 703	275
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	102	55
10	When Limited by Condenser Water	102	55
11	Average Number of Employees	4	5
12	Net Generation Exclusive of Plant Use - KWh	124 826 770	4 544 000
13	Cost of Plant Land and Land Rights	0	12 677
14	Structures and mprovements	21 758 429	2 897 501
15	Equipment Costs	109 513 307	25 567 566
16	Asset Retirement Costs	0	0
17	Total Cost	131 271 736	28 477 744
18	Cost per KW of nstalled Capacity (line 17/5) ncluding	938	537
19	Production Expenses Oper Supv & Engr	547 938	0
20	Fuel	5 804 002	174 453
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	364 914	0
26	Misc Steam (or Nuclear) Power Expenses	169 169	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	86 534	427
30	Maintenance of Structures	224 123	25 304
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	742 221	783 884
33	Maintenance of Misc Steam (or Nuclear) Plant	85 263	0
34	Total Production Expenses	8 024 164	984 068
35	Expenses per Net KWh	0 0643	0 2166
36	Fuel Kind (Coal Gas Oil or Nuclear)	Gas	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	3 543 892	83 473
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1 035 000	1 036 991
40	Avg Cost of Fuel/unit as Delvd f o b during year	2	2
41	Average Cost of Fuel per Unit Burned	2	2
42	Average Cost of Fuel Burned per Million BTU	2	2
43	Average Cost of Fuel Burned per KWh Net Gen	0	0
44	Average BTU per KWh Net Generation	29 384	19 049

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants)

1. Report data for p ant n Serv ce on y.
2. Large p ants are steam p ants w th nsta ed capac ty (name p ate rat ng) of 25,000 Kw or more. Report n th s page gas turb ne and nterna combust on p ants of 10,000 Kw or more, and nuc ear p ants.
3. Ind cate by a footnote any p ant eased or operated as a jo nt fac ty.
4. If net peak demand for 60 m nutes s not ava ab e, g ve data wh ch s ava ab e, spec fy ng per od.
5. If any emp oyees attend more than one p ant, report on ne 11 the approx mate average number of emp oyees ass gnab e to each p ant.
6. If gas s used and purchased on a therm bas s report the Btu content or the gas and the quant ty of fue burned converted to Mct.
7. Quant t es of fue burned (L ne 38) and average cost per un t of fue burned (L ne 41) must be cons stent w th charges to expense accounts 501 and 547 (L ne 42) as show on L ne 20.
8. If more than one fue s burned n a p ant furn sh on y the compos te heat rate for a fue s burned.

Line No	tem (a)	Plant Name: West Phoenix 2 (b)	Plant Name: West Phoenix 3 (c)
		West Phoenix 2 Combined Cycle	West Phoenix 3 Combined Cycle
1	Kind of Plant (nternal Comb Gas Turb Nuclear	Combined Cycle	Combined Cycle
2	Type of Constr (Conventional Outdoor Boiler etc)	More than 50% Outdoors	More than 50% Outdoors
3	Year Originally Constructed	1905	1905
4	Year Last Unit was nstalled	1905	1905
5	Total nstalled Cap (Max Gen Name Plate Ratings-MW)	132	132
6	Net Peak Demand on Plant - MW (60 minutes)	86	87
7	Plant Hours Connected to Load	5 147	3 684
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	88	88
10	When Limited by Condenser Water	88	88
11	Average Number of Employees	11	8
12	Net Generation Exclusive of Plant Use - KWh	252 980 568	251 433 139
13	Cost of Plant Land and Land Rights	3 179	4 803
14	Structures and mprovements	2 711 645	5 425 037
15	Equipment Costs	49 491 214	73 162 905
16	Asset Retirement Costs	0	0
17	Total Cost	52 206 038	78 592 745
18	Cost per KW of nstalled Capacity (line 17/5) ncluding	396	595
19	Production Expenses Oper Supv & Engr	288 591	286 825
20	Fuel	10 534 948	9 407 121
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	357 200	355 015
26	Misc Steam (or Nuclear) Power Expenses	270 182	267 357
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	23 761	23 615
30	Maintenance of Structures	399 920	869 406
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	1 705 321	644 945
33	Maintenance of Misc Steam (or Nuclear) Plant	0	71
34	Total Production Expenses	13 579 923	11 854 355
35	Expenses per Net KWh	0 0537	0 0471
36	Fuel Kind (Coal Gas Oil or Nuclear)	Gas	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	2 779 671	2 335 623
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1 037 000	1 037 001
40	Avg Cost of Fuel/unit as Delvd f o b during year	4	4
41	Average Cost of Fuel per Unit Burned	4	4
42	Average Cost of Fuel Burned per Million BTU	4	4
43	Average Cost of Fuel Burned per KWh Net Gen	0	0
44	Average BTU per KWh Net Generation	11 394	9 633

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants)

1. Report data for p ant n Serv ce on y.
2. Large p ants are steam p ants w th nsta ed capac ty (name p ate rat ng) of 25,000 Kw or more. Report n th s page gas turb ne and nterna combust on p ants of 10,000 Kw or more, and nuc ear p ants.
3. Ind cate by a footnote any p ant eased or operated as a jo nt fac ty.
4. If net peak demand for 60 m nutes s not ava ab e, g ve data wh ch s ava ab e, spec fy ng per od.
5. If any emp oyees attend more than one p ant, report on ne 11 the approx mate average number of emp oyees ass gnab e to each p ant.
6. If gas s used and purchased on a therm bas s report the Btu content or the gas and the quant ty of fue burned converted to Mct.
7. Quant t es of fue burned (L ne 38) and average cost per un t of fue burned (L ne 41) must be cons stent w th charges to expense accounts 501 and 547 (L ne 42) as show on L ne 20.
8. If more than one fue s burned n a p ant furn sh on y the compos te heat rate for a fue s burned.

Line No	tem (a)	Plant Name Redhawk 2 (b)	Plant Name Palo Verde 1 (c)
		Redhawk 2 Combined Cycle	Palo Verde 1 Nuclear
1	Kind of Plant (nternal Comb Gas Turb Nuclear	Combined Cycle	Nuclear
2	Type of Constr (Conventional Outdoor Boiler etc)	More than 50% Outdoors	Less than 50% Outdoors
3	Year Originally Constructed	1905	1905
4	Year Last Unit was nstalled	1905	1905
5	Total nstalled Cap (Max Gen Name Plate Ratings-MW)	567	411
6	Net Peak Demand on Plant - MW (60 minutes)	374	400
7	Plant Hours Connected to Load	21 068	8 760
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	544	382
10	When Limited by Condenser Water	544	382
11	Average Number of Employees	18	169
12	Net Generation Exclusive of Plant Use - KWh	2 733 031 000	3 351 144 177
13	Cost of Plant Land and Land Rights	1 056 740	1 677 551
14	Structures and mprovements	11 722 731	346 236 518
15	Equipment Costs	328 365 691	891 450 680
16	Asset Retirement Costs	0	6 228 023
17	Total Cost	341 145 162	1 245 592 772
18	Cost per KW of nstalled Capacity (line 17/5) ncluding	602	3 031
19	Production Expenses Oper Supv & Engr	1 571 078	6 973 538
20	Fuel	87 899 038	23 839 833
21	Coolants and Water (Nuclear Plants Only)	0	4 914 725
22	Steam Expenses	0	2 434 096
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1 330 261	3 600 899
26	Misc Steam (or Nuclear) Power Expenses	5 123 477	13 063 334
27	Rents	0	7 090 364
28	Allowances	0	0
29	Maintenance Supervision and Engineering	82 323	1 480 761
30	Maintenance of Structures	676 436	454 008
31	Maintenance of Boiler (or reactor) Plant	0	1 380 038
32	Maintenance of Electric Plant	4 170 722	2 095 284
33	Maintenance of Misc Steam (or Nuclear) Plant	4 283	952 561
34	Total Production Expenses	100 857 618	68 279 441
35	Expenses per Net KWh	0 0369	0 0204
36	Fuel Kind (Coal Gas Oil or Nuclear)	Gas	Nuclear
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	kg
38	Quantity (Units) of Fuel Burned	18 608 099	544
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	2 064 000	66 704
40	Avg Cost of Fuel/unit as Delvd f o b during year	5	0
41	Average Cost of Fuel per Unit Burned	5	43 800
42	Average Cost of Fuel Burned per Million BTU	5	1
43	Average Cost of Fuel Burned per KWh Net Gen	0	0
44	Average BTU per KWh Net Generation	7 026	10 292

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants) *(Continued)*

9. Items under Cost of P ant are based on U. S. of A. Accounts. Product on expenses do not nc ude Purchased Power, System Contro and Load D spatch ng, and Other Expenses C ass f ed as Other Power Supp y Expenses.
10. For IC and GT p ants, report Operat ng Expenses, Account Nos. 547 and 549 on L ne 25 "E ectr c Expenses," and Ma ntenance Account Nos. 553 and 554 on L ne 32, "Ma ntenance of E ectr c P ant." Ind cate p ants des gned for peak oad serv ce. Des gnate automat ca y operated p ants.
11. For a p ant equ pped w th comb nat ons of foss fue steam, nuc ear steam, hydro, nterna combust on or gas turb ne equ pment, report each as a separate p ant. However, f a gas turb ne un t funct ons n a comb ned cyc e operat on w th a convent ona steam un t, nc ude the gas turb ne w th the steam p ant.
12. If a nuc ear power generat ng p ant, br ef y exp a n by footnote (a) account ng method for cost of power generated nc ud ng any excess costs attr buted to research and deve opment; (b) types of cost un ts used for the var ous components of fue cost; and (c) any other nformat ve data concern ng p ant type fue used, fue enr chment type and quant ty for the report per od and other phys ca and operat ng character st cs of p ant.

P ant Name:	Four Corners 4	P ant Name:	Four Corners 5	P ant Name:	Yucca 1	L ne No.
	(d)		(e)		(f)	
	Four Corners 4 Steam		Four Corners 5 Steam		Yucca 1 Comb Turbine	
	Steam		Steam		Comb Turbine	1
	More than 50% Outdoors		More than 50% Outdoors		More than 50% Outdoors	2
	1905		1905		1 971	3
	1 970		1 970		2 008	4
	515		515		24	5
	477		484		19	6
	5 084		6 996		324	7
	0		0		0	8
	485		485		19	9
	485		485		19	10
	90		65		1	11
	2 171 184 740		2 779 806 772		3 106 000	12
	32 936		31 110		33 986	13
	95 857 398		56 061 879		1 034 716	14
	727 094 678		717 348 068		6 701 549	15
	11 704 878		11 712 056		0	16
	834 689 890		785 153 113		7 770 251	17
	1 621		1 525		324	18
	2 335 530		2 485 921		21 711	19
	89 026 070		113 291 013		151 595	20
	0		0		0	21
	8 801 254		10 822 037		0	22
	0		0		0	23
	0		0		0	24
	500 323		500 323		15 046	25
	5 194 734		4 277 515		6 556	26
	462 883		462 883		0	27
	2 483 986		3 180 292		0	28
	1 191 893		1 326 891		2 685	29
	4 558 541		4 273 777		1 222	30
	14 478 395		8 504 500		0	31
	4 320 971		802 294		166 831	32
	1 517 593		1 678 018		0	33
	134 872 173		151 605 464		365 646	34
	0 0621		0 0545		0 1177	35
Coal	Gas	Coal	Gas	Oil	Gas	36
T	Mcf	T	Mcf	bbl	Mcf	37
1 164 984	265 730	1 506 755	343 541	0	56 618	38
9 146	1 016 843	9 132	1 017 637	0	1 027 023	39
68	10	65	9	0	3	40
74	12	73	11	0	3	41
4	12	4	11	0	3	42
0	0	0	0	0	0	43
9 939	9 939	10 025	10 025	0	18 721	44

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants) *(Continued)*

9. Items under Cost of P ant are based on U. S. of A. Accounts. Product on expenses do not nc ude Purchased Power, System Contro and Load D spatch ng, and Other Expenses C ass f ed as Other Power Supp y Expenses.
10. For IC and GT p ants, report Operat ng Expenses, Account Nos. 547 and 549 on L ne 25 "E ectr c Expenses," and Ma ntenance Account Nos. 553 and 554 on L ne 32, "Ma ntenance of E ectr c P ant." Ind cate p ants des gned for peak oad serv ce. Des gnate automat ca y operated p ants.
11. For a p ant equ pped w th comb nat ons of foss fue steam, nuc ear steam, hydro, nterna combust on or gas turb ne equ pment, report each as a separate p ant. However, f a gas turb ne un t funct ons n a comb ned cyc e operat on w th a convent ona steam un t, nc ude the gas turb ne w th the steam p ant.
12. If a nuc ear power generat ng p ant, br ef y exp a n by footnote (a) account ng method for cost of power generated nc ud ng any excess costs attr buted to research and deve opment; (b) types of cost un ts used for the var ous components of fue cost; and (c) any other nformat ve data concern ng p ant type fue used, fue enr chment type and quant ty for the report per od and other phys ca and operat ng character st cs of p ant.

P ant Name:	Yucca 4 (d)	P ant Name:	Yucca 5 (e)	P ant Name:	Yucca 6 (f)	L ne No.
	Yucca 4 Comb Turbine		Yucca 5 Comb Turbine		Yucca 6 Comb Turbine	
	Comb Turbine		Comb Turbine		Comb Turbine	1
	More than 50% Outdoors		More than 50% Outdoors		More than 50% Outdoors	2
	1905		1905		2 007	3
	2 008		2 008		2 008	4
	72		61		61	5
	49		47		48	6
	81		2 075		2 011	7
	0		0		0	8
	54		48		48	9
	54		48		48	10
	1		3		3	11
	1 144 000		63 958 000		61 218 000	12
	0		13 711		0	13
	719 827		3 389 993		1 469 762	14
	13 465 311		39 925 748		39 905 194	15
	0		0		0	16
	14 185 138		43 329 452		41 374 956	17
	197		710		678	18
	7 997		456 465		436 910	19
	760 177		3 441 588		3 369 966	20
	0		0		0	21
	0		0		0	22
	0		0		0	23
	0		0		0	24
	4 164		232 780		222 808	25
	2 415		257 414		246 387	26
	0		0		0	27
	0		0		0	28
	989		55 294		52 925	29
	2 816		126 510		123 362	30
	0		0		0	31
	161 867		313 759		267 047	32
	0		30 863		183 841	33
	940 425		4 914 673		4 903 246	34
	0 8220		0 0768		0 0801	35
Oil	Gas	Oil	Gas	Oil	Gas	36
bbl	Mcf	bbl	Mcf	bbl	Mcf	37
0	733 265	0	703 458	0	703 458	38
0	1 026 002	0	1 025 999	0	1 025 999	39
0	5	0	5	0	5	40
0	5	0	5	0	5	41
0	5	0	5	0	5	42
0	0	0	0	0	0	43
0	11 763	0	11 790	0	11 790	44

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants) *(Continued)*

9. Items under Cost of P ant are based on U. S. of A. Accounts. Product on expenses do not nc ude Purchased Power, System Contro and Load D spatch ng, and Other Expenses C ass f ed as Other Power Supp y Expenses.
10. For IC and GT p ants, report Operat ng Expenses, Account Nos. 547 and 549 on L ne 25 "E ectr c Expenses," and Ma ntenance Account Nos. 553 and 554 on L ne 32, "Ma ntenance of E ectr c P ant." Ind cate p ants des gned for peak oad serv ce. Des gnate automat ca y operated p ants.
11. For a p ant equ pped w th comb nat ons of foss fue steam, nuc ear steam, hydro, nterna combust on or gas turb ne equ pment, report each as a separate p ant. However, f a gas turb ne un t funct ons n a comb ned cyc e operat on w th a convent ona steam un t, nc ude the gas turb ne w th the steam p ant.
12. If a nuc ear power generat ng p ant, br ef y exp a n by footnote (a) account ng method for cost of power generated nc ud ng any excess costs attr buted to research and deve opment; (b) types of cost un ts used for the var ous components of fue cost; and (c) any other nformat ve data concern ng p ant type fue used, fue enr chment type and quant ty for the report per od and other phys ca and operat ng character st cs of p ant.

P ant Name:	Saguaro 2	P ant Name:	Saguaro 3	P ant Name:	Ocot o 1	L ne No.
	(d)		(e)		(f)	
	Saguaro 2 Comb Turbine		Saguaro 3 Comb Turbine		Ocotillo 1 Comb Turbine	
	Comb Turbine		Comb Turbine		Comb Turbine	1
	More than 50% Outdoors		More than 50% Outdoors		More than 50% Outdoors	2
	1905		1905		1 972	3
	2 002		2 002		1 973	4
	53		78		53	5
	53		78		55	6
	219		1 216		195	7
	0		0		0	8
	55		79		55	9
	55		79		55	10
	0		1		7	11
	7 274 000		69 275 000		5 488 590	12
	15 559		21 558		152 481	13
	3 142 584		2 913 958		5 173 049	14
	26 985 596		36 732 784		32 425 037	15
	0		0		0	16
	30 143 739		39 668 300		37 750 567	17
	569		509		712	18
	0		0		24 093	19
	410 371		4 061 082		227 956	20
	0		0		0	21
	0		0		0	22
	0		0		0	23
	0		0		0	24
	0		0		16 045	25
	12 516		119 203		7 438	26
	0		0		0	27
	0		0		0	28
	683		6 507		3 805	29
	6 720		125 265		10 584	30
	0		0		0	31
	193 595		657 217		2 349 803	32
	4 097		14 472		29 527	33
	627 982		4 983 746		2 669 251	34
	0 0863		0 0719		0 4863	35
	Gas		Gas		Gas	36
	Mcf		Mcf		Mcf	37
	110 127		675 095		156 757	38
	1 040 008		1 034 001		1 034 994	39
	4		6		1	40
	4		6		1	41
	4		6		1	42
	0		0		0	43
	15 746		10 076		29 560	44

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants) *(Continued)*

9. Items under Cost of P ant are based on U. S. of A. Accounts. Product on expenses do not nc ude Purchased Power, System Contro and Load D spatch ng, and Other Expenses C ass f ed as Other Power Supp y Expenses.
10. For IC and GT p ants, report Operat ng Expenses, Account Nos. 547 and 549 on L ne 25 "E ectr c Expenses," and Ma ntenance Account Nos. 553 and 554 on L ne 32, "Ma ntenance of E ectr c P ant." Ind cate p ants des gned for peak oad serv ce. Des gnate automat ca y operated p ants.
11. For a p ant equ pped w th comb nat ons of foss fue steam, nuc ear steam, hydro, nterna combust on or gas turb ne equ pment, report each as a separate p ant. However, f a gas turb ne un t funct ons n a comb ned cyc e operat on w th a convent ona steam un t, nc ude the gas turb ne w th the steam p ant.
12. If a nuc ear power generat ng p ant, br ef y exp a n by footnote (a) account ng method for cost of power generated nc ud ng any excess costs attr buted to research and deve opment; (b) types of cost un ts used for the var ous components of fue cost; and (c) any other nformat ve data concern ng p ant type fue used, fue enr chment type and quant ty for the report per od and other phys ca and operat ng character st cs of p ant.

P ant Name:	Ocot o 4	P ant Name:	Ocot o 5	P ant Name:	Ocot o 6	L ne No.
	(d)		(e)		(f)	
	Ocotillo 4 Comb Turbine		Ocotillo 5 Comb Turbine		Ocotillo 6 Comb Turbine	
	Comb Turbine		Comb Turbine		Comb Turbine	1
	More than 50% Outdoors		More than 50% Outdoors		More than 50% Outdoors	2
	1905		1905		2 019	3
	2 019		2 019		2 019	4
	140		140		140	5
	103		104		102	6
	1 855		1 453		2 047	7
	0		0		0	8
	102		102		102	9
	102		102		102	10
	5		4		3	11
	126 702 430		106 262 740		152 579 690	12
	0		0		0	13
	21 404 284		21 950 139		21 931 234	14
	107 222 793		110 753 233		110 630 963	15
	0		0		0	16
	128 627 077		132 703 372		132 562 197	17
	919		948		947	18
	556 171		466 449		669 762	19
	5 138 664		4 599 265		6 746 204	20
	0		0		0	21
	0		0		0	22
	0		0		0	23
	0		0		0	24
	370 398		310 645		446 046	25
	171 711		144 010		206 780	26
	0		0		0	27
	0		0		0	28
	87 835		73 665		105 774	29
	230 874		202 063		273 952	30
	0		0		0	31
	741 461		820 578		749 949	32
	0		31 275		94 687	33
	7 297 114		6 647 950		9 293 154	34
	0 0576		0 0626		0 0609	35
	Gas		Gas		Gas	36
	Mcf		Mcf		Mcf	37
	2 923 933		3 674 147		4 064 353	38
	1 035 000		1 035 000		1 035 000	39
	2		1		2	40
	2		1		2	41
	2		1		2	42
	0		0		0	43
	23 885		35 786		27 570	44

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants) *(Continued)*

9. Items under Cost of P ant are based on U. S. of A. Accounts. Product on expenses do not nc ude Purchased Power, System Contro and Load D spatch ng, and Other Expenses C ass f ed as Other Power Supp y Expenses.
10. For IC and GT p ants, report Operat ng Expenses, Account Nos. 547 and 549 on L ne 25 "E ectr c Expenses," and Ma ntenance Account Nos. 553 and 554 on L ne 32, "Ma ntenance of E ectr c P ant." Ind cate p ants des gned for peak oad serv ce. Des gnate automat ca y operated p ants.
11. For a p ant equ pped w th comb nat ons of foss fue steam, nuc ear steam, hydro, nterna combust on or gas turb ne equ pment, report each as a separate p ant. However, f a gas turb ne un t funct ons n a comb ned cyc e operat on w th a convent ona steam un t, nc ude the gas turb ne w th the steam p ant.
12. If a nuc ear power generat ng p ant, br ef y exp a n by footnote (a) account ng method for cost of power generated nc ud ng any excess costs attr buted to research and deve opment; (b) types of cost un ts used for the var ous components of fue cost; and (c) any other nformat ve data concern ng p ant type fue used, fue enr chment type and quant ty for the report per od and other phys ca and operat ng character st cs of p ant.

P ant Name:	West Phoen x 2	P ant Name:	Sundance	P ant Name:	West Phoen x 1	L ne No.
	(d)		(e)		(f)	
	West Phoenix 2 Comb Turbine		Sundance Comb Turbine		West Phoenix 1 Combined Cycle	
	Comb Turbine		Comb Turbine		Combined Cycle	1
	More than 50% Outdoors		More than 50% Outdoors		More than 50% Outdoors	2
	1905		1905		1 976	3
	1 973		2 002		2 003	4
	53		605		132	5
	51		448		86	6
	262		9 687		5 312	7
	0		0		0	8
	55		420		88	9
	55		420		88	10
	3		9		7	11
	8 781 000		364 774 520		266 823 063	12
	6 527		681 252		4 359	13
	2 824 181		16 626 984		8 935 718	14
	26 290 391		320 336 011		62 537 350	15
	0		0		0	16
	29 121 099		337 644 247		71 477 427	17
	549		558		541	18
	0		0		304 382	19
	307 009		15 376 719		10 977 860	20
	0		0		0	21
	0		0		0	22
	0		0		0	23
	0		0		0	24
	0		541 678		376 745	25
	0		3 603 330		283 722	26
	0		0		0	27
	0		0		0	28
	825		153 500		25 061	29
	7 265		1 422 241		1 319 962	30
	0		0		0	31
	593 831		4 598 949		661 260	32
	0		44 418		14 936	33
	908 930		25 740 835		13 963 928	34
	0 1035		0 0706		0 0523	35
	Gas		Gas		Gas	36
	Mcf		Mcf		Mcf	37
	149 749		3 714 200		2 856 666	38
	1 036 995		1 029 999		1 037 000	39
	2		4		4	40
	2		4		4	41
	2		4		4	42
	0		0		0	43
	17 685		10 488		11 102	44

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants) *(Continued)*

9. Items under Cost of P ant are based on U. S. of A. Accounts. Product on expenses do not nc ude Purchased Power, System Contro and Load D spatch ng, and Other Expenses C ass f ed as Other Power Supp y Expenses.
10. For IC and GT p ants, report Operat ng Expenses, Account Nos. 547 and 549 on L ne 25 "E ectr c Expenses," and Ma ntenance Account Nos. 553 and 554 on L ne 32, "Ma ntenance of E ectr c P ant." Ind cate p ants des gned for peak oad serv ce. Des gnate automat ca y operated p ants.
11. For a p ant equ pped w th comb nat ons of foss fue steam, nuc ear steam, hydro, nterna combust on or gas turb ne equ pment, report each as a separate p ant. However, f a gas turb ne un t funct ons n a comb ned cyc e operat on w th a convent ona steam un t, nc ude the gas turb ne w th the steam p ant.
12. If a nuc ear power generat ng p ant, br ef y exp a n by footnote (a) account ng method for cost of power generated nc ud ng any excess costs attr buted to research and deve opment; (b) types of cost un ts used for the var ous components of fue cost; and (c) any other nformat ve data concern ng p ant type fue used, fue enr chment type and quant ty for the report per od and other phys ca and operat ng character st cs of p ant.

P ant Name:	West Phoen x 4	P ant Name:	West Phoen x 5	P ant Name:	Redhawk 1	L ne No.
	(d)		(e)		(f)	
	West Phoenix 4 Combined Cycle		West Phoenix 5 Combined Cycle		Redhawk 1 Combined Cycle	
	Combined Cycle		Combined Cycle		Combined Cycle	1
	More than 50% Outdoors		More than 50% Outdoors		More than 50% Outdoors	2
	1905		1905		2 002	3
	2 003		2 003		2 002	4
	136		570		573	5
	109		500		370	6
	3 817		16 039		21 400	7
	0		0		0	8
	117		506		544	9
	117		506		544	10
	5		19		28	11
	327 400 000		1 745 293 812		2 756 992 000	12
	32 909		18 896		1 128 040	13
	9 884 858		21 894 691		13 467 359	14
	87 161 419		321 311 630		346 015 775	15
	0		0		0	16
	97 079 186		343 225 217		360 611 174	17
	714		602		629	18
	373 485		1 990 965		1 585 369	19
	12 949 484		60 408 654		86 541 838	20
	0		0		0	21
	0		0		0	22
	0		0		0	23
	0		0		0	24
	462 277		2 464 294		1 342 361	25
	348 135		2 083 090		5 170 081	26
	0		0		0	27
	0		0		0	28
	30 750		6 379		754 171	29
	323 244		462 258		682 574	30
	0		0		0	31
	1 296 161		6 759 115		5 011 878	32
	0		901 843		9 015	33
	15 783 536		75 076 598		101 097 287	34
	0 0482		0 0430		0 0367	35
	Gas		Gas		Gas	36
	Mcf		Mcf		Mcf	37
	2 755 591		12 055 387		18 853 160	38
	1 037 000		2 074 000		2 064 000	39
	5		5		5	40
	5		5		5	41
	5		5		4	42
	0		0		0	43
	8 728		7 163		7 057	44

STEAM ELECTRIC GENERATING PLANT STATISTICS (Large P ants) *(Continued)*

9. Items under Cost of P ant are based on U. S. of A. Accounts. Product on expenses do not nc ude Purchased Power, System Contro and Load D spatch ng, and Other Expenses C ass f ed as Other Power Supp y Expenses.
10. For IC and GT p ants, report Operat ng Expenses, Account Nos. 547 and 549 on L ne 25 "E ectr c Expenses," and Ma ntenance Account Nos. 553 and 554 on L ne 32, "Ma ntenance of E ectr c P ant." Ind cate p ants des gned for peak oad serv ce. Des gnate automat ca y operated p ants.
11. For a p ant equ pped w th comb nat ons of foss fue steam, nuc ear steam, hydro, nterna combust on or gas turb ne equ pment, report each as a separate p ant. However, f a gas turb ne un t funct ons n a comb ned cyc e operat on w th a convent ona steam un t, nc ude the gas turb ne w th the steam p ant.
12. If a nuc ear power generat ng p ant, br ef y exp a n by footnote (a) account ng method for cost of power generated nc ud ng any excess costs attr buted to research and deve opment; (b) types of cost un ts used for the var ous components of fue cost; and (c) any other nformat ve data concern ng p ant type fue used, fue enr chment type and quant ty for the report per od and other phys ca and operat ng character st cs of p ant.

P ant Name: (d)	P ant Name: (e)	P ant Name: (f)	L ne No.
Palo Verde 2 Nuclear	Palo Verde 3 Nuclear	0	
Nuclear	Nuclear		1
Less than 50% Outdoors	Less than 50% Outdoors		2
1905	1905		3
1 988	1 988		4
411	411		5
394	398		6
7 808	7 707		7
0	0		8
382	382		9
382	382		10
185	189		11
2 946 072 597	2 907 059 255		12
1 118 955	1 621 284		13
219 177 464	342 000 068		14
606 677 408	859 211 984		15
(869 336)	(6 693 409)		16
826 104 491	1 196 139 927	0	17
2 010	2 910	0	18
6 461 327	6 827 028		19
19 558 765	18 805 782		20
4 914 725	4 914 724		21
3 041 703	3 101 501		22
0	0		23
0	0		24
3 556 077	3 446 091		25
13 101 231	13 031 682		26
7 090 364	7 090 364		27
0	0		28
1 418 579	2 816 927		29
1 003 687	1 006 057		30
5 191 258	4 506 409		31
4 616 512	4 884 868		32
1 342 402	1 457 406		33
71 296 630	71 888 839	0	34
0 0242	0 0247		35
Nuclear	Nuclear		36
kg	kg		37
447	429		38
66 704	66 704		39
2 423	2 387		40
43 800	43 800		41
1	1		42
0	0		43
10 292	10 292		44

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

The Cholla Plant is jointly owned and is operated by Arizona Public Service Company.

(b) Concept: PlantName

The Cholla Plant is jointly owned and is operated by Arizona Public Service Company.

(c) Concept: PlantName

The Four Corners Plant is jointly owned and is operated by Arizona Public Service Company.

(d) Concept: PlantName

The Four Corners Plant is jointly owned and is operated by Arizona Public Service Company.

(e) Concept: PlantName

The Palo Verde Nuclear Units have pressurized water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of nuclear fuel is amortized to fuel expense (acct. 518) based on the fuel burns, or quantity of heat, produced in the generation of energy. Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from the reactors. Additional information on APS' nuclear fuel program and nuclear decommissioning is detailed in the Notes to Comparative Financial Statements.

(f) Concept: PlantName

The Palo Verde Nuclear Units have pressurized water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of nuclear fuel is amortized to fuel expense (acct. 518) based on the fuel burns, or quantity of heat, produced in the generation of energy. Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from the reactors. Additional information on APS' nuclear fuel program and nuclear decommissioning is detailed in the Notes to Comparative Financial Statements.

(g) Concept: PlantName

The Palo Verde Nuclear Units have pressurized water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of nuclear fuel is amortized to fuel expense (acct. 518) based on the fuel burns, or quantity of heat, produced in the generation of energy. Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from the reactors. Additional information on APS' nuclear fuel program and nuclear decommissioning is detailed in the Notes to Comparative Financial Statements.

(h) Concept: PlantName

Sundance: Generator Name Plate Rating is 605 MW at 15 degrees C and 0.85 Power Factor. Plant Output is limited by gas turbine.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	

27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0

26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	[a] Solar Plants												
2	Red Rock	2016	40		118,390	91,942,800	2,298,570				Solar		
3	Hyder I	2011	16		40,609	71,272,116	4,454,507				Solar		
4	Hyder II	2013	14		38,070	51,835,655	3,702,547				Solar		
5	Cotton Center	2011	17		40,866	83,016,408	4,883,318				Solar		
6	Paloma	2011	17		39,554	69,914,855	4,112,639				Solar		
7	Chino Valley	2012	19		46,771	88,763,364	4,671,756				Solar		
8	Foothills I & II	2013	35		104,280	145,303,444	4,151,527				Solar		
9	Gila Bend I	2014	16		48,640	56,429,614	3,526,851				Solar		
10	Gila Bend II	2014	16		47,403	56,429,614	3,526,851				Solar		
11	Desert Star	2015	10		31,627	35,733,100	3,573,310				Solar		
12	Luke AFB	2015	10		30,771	30,752,165	3,075,217				Solar		
13	Other Residential/Commercial	[c] 1997	37			146,695,091	3,964,732				Solar		
14	[b] TOTAL Solar Operation/Maint.		247		586,981	928,088,226	3,757,442	5,061,409					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Solar is not required to be reported on these pages but we are choosing to report it here. This section shows APS Owned solar facilities.

(b) Concept: PlantName

O&M Expenses for Solar Plants are not broken out by plant or between Operations and Maintenance.

(c) Concept: YearPlantOriginallyConstructed

Original constructions spans from 1997-2021

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary se
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o) fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	D
1																			
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34																			
35	TOTAL																		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	PALO VERDE	KYRENE	500	500	(3) STEEL (A)		75	1	1780 ACSR	4,014,277	22,181,381	26,195,658				
2	PALO VERDE	WESTWING #2	500	500	(3) STEEL (A)		45	1	1780 ACSR	8,522	7,503,395	7,511,917				
3	PALO VERDE	WESTWING	500	500	(3) STEEL (A)		47	1	1780 ACSR	0	3,619,218	3,619,218				
4	FOUR CORNERS	COLORADO RIVER	500	500	(3) STEEL	366		1	2156 ACSR	8,687,862	42,053,778	50,741,640				
5	NAVAJO PLANT	WESTWING	500	500	(3) STEEL (A)		256	1	2156 ACSR	602,279	8,657,427	9,259,706				
6	NAVAJO PLANT	MOENKOPI	500	500	(3) STEEL (A)		76	1	2156 ACSR	0	1,208,159	1,208,159				
7	MOENKOPI	WESTWING	500	500	(3) STEEL (A)		180	1	2156 ACSR	1,443,668	7,508,189	8,951,857				
8	CHOLLA	SAGUARO	500	500	(3) STEEL	206		1	2156 ACSR	812,417	61,606,715	62,419,132				
9	PALO VERDE	NORTH GILA	500	500	(3) STEEL (A)		120	1	2156 ACSR	345,185	4,730,608	5,075,793				
10	WESTWING	MEAD	500	500	(3) STEEL (A)	243		1	1590 KCM	1,175,680	17,251,076	18,426,756				
11	MEAD	MARKET PLACE	500	500	(3) STEEL (A)	13		1	1590 KCM	2,117,445	1,518,180	3,635,625				
12	GILA RIVER	JOJOBA SWITCHYARD	500	500	(3) STEEL	19		2	1780 ACSR	906,760	579,009	1,485,769				
13	PALO VERDE	RUDD	500	500	(3) STEEL (A)	36		1	1780 ACSR	13,323,303	29,540,970	42,864,273				
14	PALO VERDE	HASSAYAMPA	500	500	(3) STEEL (A)		3	1	1780 ACSR	354,415	617,408	971,823				

15	MORGAN	PINNACLE PEAK	500	500	(3) STEEL (A)	27	6	1	1780 ACSR	21,035,086	47,210,083	68,245,169				
16	WESTWING	DUGAS LOOP	500	500	(3) STEEL			1	2156 ACSR	0	3,718,999	3,718,999				
17	HASSAYAMPA	NORTH GILA	500	500	(3) STEEL (A)	112		1	2156 ACSR	5,352,427	104,541,298	109,893,725				
18	PALO VERDE	DELANEY	500	500	(3) STEEL (A)	15		1	1780 ACSR	4,186,928	14,957,241	19,144,169				
19	DELANEY	SUN VALLEY	500	500	(3) STEEL (A)	28		1	1780 ACSR	8,032,709	35,262,109	43,294,818				
20	SUN VALLEY	MORGAN	500	500	(1) STEEL	38		2	1780 ACSR	13,906,621	93,956,636	107,863,257				
21	FOUR CORNERS/CHOLLA	PINNACLE PEAK	345	345	(3) STEEL (C)	567	12	2	795 ACSR	1,123,440	37,628,552	38,751,992				
22	FOUR CORNERS/CHOLLA - 1	PINNACLE PEAK - 1	345	345	(3) STEEL	1		1	2156 ACSS	0	0	0				
23	FOUR CORNERS/CHOLLA - 2	PINNACLE PEAK - 2	345	345	(3) STEEL (D)		13	1	795 ACSR	0	0	0				
24	MORGAN	PINNACLE PEAK	230	230	(3) STEEL	1		1	2156 ACSS	15,362	1,636,422	1,651,784				
25	WESTWING-EL SOL	SURPRISE	230	230	(1) STEEL	11		1	954 ACSR	666,954	5,205,688	5,872,642				
26	CHOLLA PLANT	COCONINO	230	230	(2) WOOD	88		1	795 ACSR	140,451	5,158,753	5,299,204				
27	VERDE	WILLOW LAKE	230	230	(2) WOOD	34		1	795 ACSR	139,566	12,286,352	12,425,918				
28	VERDE - 1	WILLOW LAKE - 1	230	230	(2) WOOD	33		1	795 ACSR	0	0	0				
29	VERDE - 2	WILLOW LAKE - 2	230	230	(1) STEEL	1		2	954 ACSR	0	0	0				
30	VERDE - 3	WILLOW LAKE - 3	69	230	(2) WOOD	60		1	954 ACSR	0	0	0				
31	PINNACLE PEAK	OCOTILLO	230	230	(3) STEEL	51		2	795 AA	5,621,186	4,371,923	9,993,109				
32	EL SOL	AGUA FRIA	230	230	(3) STEEL	6		1	1431 AA	373,661	5,441,907	5,815,568				
33	EL SOL - 1	AGUA FRIA - 1	230	230	(1) STEEL	10		1	1361 ACAR	0	0	0				
34	OCOTILLO PLANT	LINCOLN STREET	230	230	(3) STEEL	10	10	2	1431 AA	820,160	8,690,166	9,510,326				
35	OCOTILLO PLANT - 1	LINCOLN STREET - 1	230	230	(4) U.G.	1			2000 KC	0	0	0				
36	OCOTILLO PLANT - 2	LINCOLN STREET - 2	230	230	(3) STEEL		2	1	954A/1113A	0	0	0				
37	KYRENE	KNOX	230	230	(1) STEEL (A)	4			954 ACSR	91,269	486,722	577,991				
38	LINCOLN STREET	WEST PHOENIX PLANT	230	230	(3) STEEL	6		1	1113 AA	37,261	3,283,837	3,321,098				
39	SANTA ROSA	SAGUARO PLANT	230	230	(2) WOOD	62		1	954A/1113A	273,275	4,613,107	4,886,382				
40	PINNACLE PEAK-OCOTILLO	CACTUS SUB TAP	230	230	(1) STEEL	3		2	954 AA	3,206,928	5,018,293	8,225,221				
41	PINNACLE PEAK-OCOTILLO - 1	CACTUS SUB TAP - 1	230	230	(1) STEEL	0		1	954 ACSR	0	0	0				
42			230	230	(4) U.G.	1		1	1750 CU	0	0	0				

	PINNACLE PEAK-OCOTILLO - 2	CACTUS SUB TAP - 2															
43	SRP PINNACLE PEAK	DEER VALLEY TAP	230	230	(1) STEEL	3		2	954 AA	68,982	2,785,385	2,854,367					
44	LINCOLN STREET	COUNTRY CLUB	230	230	(4) U.G.	4		1	1750 CU	1,021,582	5,214,077	6,235,659					
45	SUNNYSLOPE	COUNTRY CLUB	230	230	(4) U.G.	8		1	1750 CU	85,094	7,148,105	7,233,199					
46	SUNNYSLOPE - 1	COUNTRY CLUB - 1	230	230	(4) U.G.	3		1	1750 CU	0	0	0					
47	SUNNYSLOPE - 2	COUNTRY CLUB - 2	230	230	(4) U.G.	0		1	1750 ACSR	0	0	0					
48	SUNNYSLOPE - 3	COUNTRY CLUB - 3	230	230	(4) U.G.	0		1	1750 ACSR	0	0	0					
49	SANTA ROSA	CASA GRANDE	230	230	(2) WOOD	15		1	1272 ACSR	987,879	13,569,966	14,557,845					
50	SANTA ROSA - 1	CASA GRANDE - 1	230	230	(1) WOOD	7		1	1272 ACSR	0	0	0					
51	SANTA ROSA - 2	CASA GRANDE - 2	230	230	(2) WOOD	39		1	1272 ACSR	0	0	0					
52	DEER VALLEY	ALEXANDER	230	230	(1) STEEL	8		1	954 AA	933,461	4,747,708	5,681,169					
53	PINNACLE PEAK	SUNNYSLOPE	230	230	(1) STEEL	17		1	1431A/1361ACSR	127,241	4,204,240	4,331,481					
54	OCOTILLO	SANTA ROSA	230	230	(2) WOOD	37		1	795R/1113A	22,848,367	10,698,211	33,546,578					
55	OCOTILLO - 1	SANTA ROSA - 1	230	230	(1) STEEL	7		2	954 ACSR	0	0	0					
56	ROUND VALLEY/SELIGMAN	MT FLOYD	230	230	(2) WOOD	36		1	795 ACSR	8,077	2,653,303	2,661,380					
57	ROUND VALLEY/SELIGMAN - 1	MT FLOYD - 1	230	230	(2) WOOD	2		1	795 AA	0	0	0					
58	WHITE TANKS	WEST PHOENIX	230	230	(1) STEEL	12		2	954 SSAC	7,389,772	16,031,429	23,421,201					
59	EL SOL	WHITE TANKS	230	230	(3) STEEL	9		1	954 ACSR	1,047,627	6,610,104	7,657,731					
60	PINNACLE PEAK	LONE PEAK	230	230	(3) STEEL	12		1	954 ACSR	3,600,841	7,952,028	11,552,869					
61	GILA BEND	RUDD	230	230	(1) STEEL	20		1	1750 ACSR	7,919,741	25,182,305	33,102,046					
62	GILA BEND - 1	RUDD - 1	230	230	(3) STEEL (D)		6	1	1272 ACSR	0	0	0					
63	GILA BEND - 2	RUDD - 2	230	230	(1) WOOD	12		1	1272 ACSR	0	0	0					
64	GILA BEND - 3	RUDD - 3	230	230	(2) WOOD	28		1	1272 ACSR	0	0	0					
65	GILA BEND - 4	RUDD - 4	230	230	(1) STEEL	0		1	1272 ACSR	0	0	0					
66	PALO VERDE	NORTH GILA TAP	230	230	(1) STEEL	3		2	954 AA	0	374,911	374,911					
67	PALO VERDE	KYRENE TAP	230	230	(1) STEEL	3		2	954 AA	0	383,526	383,526					
68	PALM VALLEY	SUN VALLEY	230	230	(3) STEEL	14		1	2156 ACSS	36,890,192	44,003,347	80,893,539					
69	PALM VALLEY - 1	SUN VALLEY - 1	69	230	(1) STEEL	16		1	2156 KCMIL	0	0	0					
70	SAGUARO PLANT	SANTA ROSA	115	230	(2) WOOD	42		1	954 ACSR	57,534	2,750,895	2,808,429					
71	ADAMS	MURAL	115	115	(2) WOOD	47		1	556 ACSR	454,172	2,411,272	2,865,444					
72	SANTA ROSA	ASARCO	115	115	(2) WOOD	18		1	795 ACSR	0	0	0					
73	WILLOW LAKE	BAGDAD	115	115	(2) WOOD	49		1	795 ACSR	302,378	4,577,360	4,879,738					

74	ORACLE	SAN MANUEL	115	115	(2) WOOD	21		1	556 ACSR	143,285	3,113,685	3,256,970				
75	UNDERGROUND (NON-SPECIFIC) 69KV	0	69	69	0	59			0	0	71,804,445	71,804,445				
76	OVERHEAD (NON-SPECIFIC) 69KV	0	69	69	0	2,405	31	1	0	28,964,767	715,960,528	744,925,295				
77	(a) *RELATED TRANSMISSION	0	0	0	0	2			0	0	4,935,684	4,935,684				
78	0	0	0	0	0				0	0	0	0				
79		0	0	0	0				0	0	0	0	31,943,182	4,327,882	8,413,296	44,684,360
36	TOTAL					5,011	882	85		211,666,089	1,559,156,115	1,770,822,204	31,943,182	4,327,882	8,413,296	44,684,360

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint

INCLUDES MINOR NAVAJO UNITS 1, 2, 3, FOUR CORNERS COMMON UNITS 1, 2, 3, PALO VERDE UNITS 1,2,3, REDHAWK COMBINED CYCLE UNITS 1 AND 2, AND WEST PHOENIX PLANT TO WEST PHOENIX COMBINED CYCLE RELATED TRANSMISSION

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	0	0	0.00														
2	No Transmission Line	0	0.00														
3	Additions meeting	0	0.00														
4	added or altered	0	0.00														
5	criteria for 2021	0	0.00														
44	TOTAL		0.00		0.00	0	0										

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	[a] ACOMA - SCOTTSDALE	Distribution		[b] 69	[c] 12		83	2				[d] 0
2	ADAMS - BENSON	Transmission		115								
3	ADOBE - PHOENIX	Distribution		69	12		83	2				
4	AGUA FRIA SWYD - PEORIA	Transmission		230	69	12	188	1		capacitor bank-69kV	1	48
5	AGUILA - AGUILA	Distribution		69	12		20	1		capacitor bank-69kV	1	5
6	AJO - AJO	Distribution		69	21		9	1		capacitor bank-69kV	3	9
7	ALEXANDER - PHOENIX	Transmission		69						capacitor bank-69kV	1	48
8	ALTADENA - SCOTTSDALE	Distribution		69	12		83	2				
9	ANITA - COCONINO	Distribution		69	7			1				
10	ANTELOPE - PRESCOTT	Distribution		69	12		40	2		capacitor bank-69kV	1	7
11	AQUEDUCT - PHOENIX	Distribution		69	4		40	2				
12	ARABY - YUMA	Distribution		69	12		57	2		capacitor bank-69kV	1	14
13	ARICA - ELOY	Distribution		69	12		20	1		capacitor bank-12kV	2	4
14	ARLINGTON - MARICOPA COUNTY	Distribution		69	12		16	1				
15	ARROWHEAD - GLENDALE	Distribution		69	12		83	2		capacitor bank-69kV	1	22
16	ARROYO - PHOENIX	Distribution		69	12		42	1				
17	ASARCO PIT - CASA GRANDE	Distribution		69	12		9	1				
18	ASHFORK - ASHFORK	Distribution		69	12		9	1				
19	AZTEC - DATELAND	Distribution		69	12		20	1				

20	BACON - N.W. OF SNOWFLAKE	Distribution		69	12		4	1				
21	BADGER SUB - TONOPAH	Distribution		69	12		20	1				
22	BAGDAD NEW TOWN - BAGDAD	Transmission		115	12		30	1				
23	BAGDAD 115kV CAP. - BAGDAD	Transmission		115						capacitor bank-115kV	5	39
24	BAJA - SAN LUIS	Distribution		69	12		20	1		capacitor bank-69kV	1	14
25	BALD MOUNTAIN - PRESCOTT VALLEY	Distribution		69	12		83	2		capacitor bank-12kV	4	10
26	BALD MOUNTAIN - PRESCOTT VALLEY (cb)	Distribution		69						capacitor bank-69kV	1	7
27	BASELINE - BUCKEYE	Distribution		69	12		40	2		capacitor bank-69kV	2	22
28	BEAR SPRINGS - CAMERON	Distribution		69	2			1				
29	BEARDSLEY - SURPRISE	Distribution		69	12		20	1				
30	BELL - PEORIA	Distribution		69	12		83	2				
31	BISCUIT FLATS - PHOENIX	Distribution		69						capacitor bank-69kV	1	14
32	BLACK PEAK(BOUSE APA) - PARKER - T	Transmission		161	69	12	112	1	1			
33	BLACK PEAK(BOUSE APA) - PARKER - D	Distribution		69	12		9	1				
34	BLUE RIDGE - BLUE RIDGE	Distribution		69	22		10	1				
35	BLUE WATER - N. OF PARKER	Distribution		35	12		15	1				
36	BONNEYBROOK - FLORENCE	Transmission		115	12		13	1				
37	BOOTHILL - E. OF TOMBSTONE	Transmission		115	21		20	1				
38	BOULEVARD - SCOTTSDALE	Distribution		69	12		83	2				
39	BROADWAY SUBSTATION - GOODYEAR	Distribution		69	34		160	2				
40	BUCKEYE - BUCKEYE - T	Transmission		230	69	12	267	2				
41	BUCKEYE - BUCKEYE - D	Distribution		69	12		20	1				
42	BUFFALO - PHOENIX	Distribution		69	12		83	2				
43	BULLARD SUBSTATION - GOODYEAR	Distribution		69	12		82	2				
44	BUNYAN - NW. OF GILA BEND	Distribution		69	12		7	1		capacitor bank-69kV	1	10
45	BUTTE - TEMPE	Distribution		69	12		164	4				
46	CACTUS-SCOTTSDALE - T	Transmission		230	69	12	561	3				
47	CACTUS-SCOTTSDALE - D	Distribution		69	12		123	3		capacitor bank-69kV	1	48
48	CALDERWOOD - PEORIA	Distribution		69	12		83	2				
49	CAMELBACK - SCOTTSDALE	Distribution		69	12		123	3				
50	CAMERON - CAMERON	Distribution		69	12		2	1				
51	CANAL - PHOENIX	Distribution		69	12		83	2				
52	CAPITAL BUTTE - SEDONA	Distribution		69	12		40	2		capacitor bank-12kV	4	14

53	CASA GRANDE - CASA GRANDE 230-69kv	Transmission		230	69	12	187	1				
54	CASA GRANDE - CASA GRANDE 230-12kv	Transmission		230	12		50	1				
55	CASA GRANDE - CASA GRANDE - 69kv	Distribution		69	12		20	1				
56	CAVE CREEK - CAVE CREEK	Distribution		69	12		40	2				
57	CEDAR MOUNTAIN - WILLIAMS	Transmission		525								
58	CELEBORN - BUCKEYE	Distribution		69	12		40	2		capacitor bank-12kV	4	5
59	CENTURY - SCOTTSDALE	Distribution		69	12		83	2				
60	CHANDLER - CHANDLER	Distribution		69	12		83	2				
61	CHAPARRAL - SCOTTSDALE	Distribution		69	12		83	2				
62	CHERYL - PHOENIX	Distribution		69	12		40	2				
63	CHILDS - CAMP VERDE	Transmission		69								
64	CHINO VALLEY - CHINO VALLEY	Distribution		69	12		38	2				
65	CHOLLA - JOSEPH CITY - 525 kv	Transmission	Attended	525	345	35	1002	6		capacitor bank-525kV	1	569
66	CHOLLA - JOSEPH CITY (sr)	Transmission	Attended	525						shunt reactor-525kV	4	312
67	CHOLLA - JOSEPH CITY 345-230kv	Transmission	Attended	345	230	12	203	1		capacitor bank-345kV	2	282
68	CHOLLA - JOSEPH CITY 345-69kv	Transmission	Attended	345	69		143	1				
69	CHOLLA - JOSEPH CITY 230-69kv	Transmission	Attended	230	69	4	100	1				
70	CIELO GRANDE - PHOENIX	Distribution		69	12		124	3		capacitor bank-12kV	2	7
71	CLINIC - SCOTTSDALE	Distribution		69	12		40	2		capacitor bank-12kV	4	7
72	COCONINO - FLAGSTAFF - T	Transmission		230	69	12	375	2				
73	COCONINO - FLAGSTAFF - D	Distribution		69	12		40	2		capacitor bank-69kV	2	36
74	COCOPAH - W. OF YUMA	Distribution		69	12		83	2		capacitor bank-69kV	1	14
75	COLDWATER - GOODYEAR	Distribution		69	12		83	2		capacitor bank-69kV	1	29
76	COLORADO - N. OF PARKER	Distribution		69	12		9	1				
77	COLTER - AVONDALE	Distribution		69	12		83	2				
78	COMMERCE - PHOENIX	Distribution		69	12		125	3		capacitor bank-12kV	5	14
79	CONLEY - SNOWFLAKE	Transmission		69								
80	CONTRAIL - EL MIRAGE	Distribution		69	35		300	6				
81	COOLIDGE - N. OF COOLIDGE	Distribution		12								
82	COPPER CANYON - N. OF CAMP VERDE	Distribution		69	12		40	2		capacitor bank-12kV	4	12
83	CORDES - CORDES JUNCTION	Distribution		69	12		20	1				
84	CORNVILLE - CORNVILLE	Distribution		69	12		20	1			1	7

										capacitor bank-69kV		
85	COTTON CENTER - N. OF GILA BEND	Distribution		69	12		40	2				
86	COTTONWOOD - COTTONWOOD	Distribution		69	12		40	2		capacitor bank-69kV	1	11
87	COTTONWOOD - COTTONWOOD (cb)	Distribution		69						capacitor bank-12kV	2	6
88	COUNTRY CLUB - PHOENIX - D	Distribution		69	12		125	3				
89	COUNTRY CLUB - PHOENIX - T	Transmission		230	69	12	355	2				
90	COUNTY LINE - TONOPAH	Distribution		69	12		40	2		capacitor bank-69kV	4	14
91	COUNTY LINE - TONOPAH (cb)	Distribution		69						capacitor bank - 12kV	4	5
92	CROSSROADS - N. OF PARKER	Distribution		35	12		20	1				
93	DAISY MOUNTAIN - PHOENIX	Distribution		69	12		42	1				
94	DALE - SCOTTSDALE	Distribution		69	12		83	2		capacitor bank-12kV	2	7
95	DALE - SCOTTSDALE (cb)	Distribution		69						capacitor bank-69kV	1	29
96	DAVENPORT - E OF WILLIAMS	Distribution		69	12		3	1				
97	DEADMAN WASH - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	2	7
98	DEADMAN WASH - PHOENIX (cb)	Distribution		69						capacitor bank-69kV	1	29
99	DEER VALLEY - PHOENIX - T	Transmission		230	69	12	564	3				
100	DEER VALLEY - PHOENIX - D	Distribution		69	12		123	3		capacitor bank-69kV	1	48
101	DEL RIO - PEORIA	Distribution		69	12		22	1				
102	DELANEY - TONOPAH	Transmission		525	69	35	269	3	1			
103	DELANO - PRESCOTT	Distribution		69	12		40	2				
104	DESERT RIDGE - SCOTTSDALE	Distribution		69	12		83	2		capacitor bank-12kV	2	10
105	DESERT SANDS - YUMA	Transmission		69								
106	DESERT SKY - BUCKEYE	Distribution		69	12		4	1				
107	DESERT SPRINGS - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	2	10
108	DEWEY - N. OF DEWEY	Distribution		69	12		40	2		capacitor bank-69kV	1	14
109	DIXILETA - N. OF SCOTTSDALE	Distribution		69	12		83	2		capacitor bank-12kV	2	7
110	DON LUIS - BISBEE	Distribution		69	12		20	1				
111	DOUBLETREE - PHOENIX	Distribution		69	12		42	1				
112	DOVE VALLEY - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	2	4
113	DOWNING - SCOTTSDALE	Distribution		69	12		123	3		capacitor bank-69kV	1	48

114	DRAKE - PAULDEN	Distribution		69						capacitor bank-69kV	3	22
115	DRY LAKE - HOLBROOK	Distribution		69	7			1				
116	DUPONT - YUMA	Distribution		69	12		20	1		capacitor bank-12kV	4	5
117	DUGAS - MAYER	Transmission		525	69	35	269	3	1	shunt reactor-525kV	1	190
118	DUGAS - MAYER (cb)	Transmission		525						capacitor bank-525kV	1	536
119	DURANGO - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	2	7
120	DYSART - SURPRISE	Distribution		69	12		123	3				
121	EAGLE - PHOENIX	Distribution		69	12		83	2				
122	EAGLE EYE - W. OF AGUILA	Transmission		230	69	12	100	2				
123	EAST END - SCOTTSDALE	Distribution		69	12		41	1		capacitor bank-12kV	2	5
124	EASTERN OFFICE - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	1	5
125	EASTGATE - CASA GRANDE	Distribution		69	12		41	1		capacitor bank-12kV	2	14
126	EGG RANCH - TONOPAH	Distribution		69	12		40	2		capicitor bank - 12kV	4	5
127	EHRENBERG - EHRENBERG	Distribution		35	12		40	2		capacitor bank-12kV	2	5
128	EL SOL - YOUNGTOWN - T	Transmission		230	69	12	373	2				
129	EL SOL - YOUNGTOWN - D	Distribution		69	12		83	2		capacitor bank-69kV	1	48
130	ELDEN - FLAGSTAFF	Distribution		69	12		40	2				
131	ENCANTO - PHOENIX	Distribution		69	12		83	2				
132	ESTRELLITA - GOODYEAR	Distribution		69	12		83	2		capacitor bank-12kV	1	4
133	EVANS CHURCHILL - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	4	10
134	FAIRVIEW - N. OF DOUGLAS	Distribution		69	12					capacitor bank-12kV	4	10
135	FALCON - WADDELL	Distribution		69	12		83	2		capacitor bank-12kV	1	5
136	FARMER - SURPRISE	Transmission		69								
137	FESTIVAL RANCH - BUCKEYE	Distribution		69	12		40	2				
138	FILLMORE - PHOENIX	Distribution		69	12		83	2		capacitor bank-69kV	1	29
139	FISH SAWMILL - N. OF FLAGSTAFF	Distribution		69	12			1				
140	FLORES - CONGRESS	Distribution		69	12		20	1		capacitor bank-69kV	2	12
141	FLYING E - WICKENBURG	Distribution		69	12		20	1		capacitor bank-69kV	2	22

142	FOOTHILLS - YUMA	Distribution		69	12		83	2		capacitor bank-69kV	2	29
143	FORTIETH PLACE - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	2	7
144	FOUR CORNERS - FRUITLAND, NM 525-345kv	Transmission	Attended	525	345	14	2050	6	1	shunt reactor 525kV	3	125
145	FOUR CORNERS - FRUITLAND, NM 345-230kv	Transmission	Attended	345	230	14	1400	2	1	shunt reactor 345kV	4	125
146	FOUR CORNERS - FRUITLAND, NM 230-69kv	Transmission	Attended	230	69	4	56	1	1	shunt reactor - 230kV	2	200
147	FREEDOM - BUCKEYE	Transmission		230	69	12	187	1				
148	GARFIELD - PHOENIX	Distribution		69	12		165	4		capacitor bank-12kV	4	10
149	GARLAND PRAIRIE - E. OF WILLIAMS	Distribution		69	12		10	1				
150	GATEWAY - PHOENIX	Distribution		69	12		42	1				
151	GAVILAN PEAK - PHOENIX - T	Transmission		230	69	12	188	1				
152	GAVILAN PEAK - PHOENIX - D	Distribution		69	12		41	1				
153	GILA BEND - GILA BEND - T	Transmission		230	69	12	200	2				
154	GILA BEND - GILA BEND - D	Distribution		69	12		83	2		capacitor bank-69kV	2	30
155	GILBERT - GILBERT	Distribution		69	12		83	2		capacitor bank-12kV	2	8
156	GILLESPIE#1 - BUCKEYE	Distribution		69	12		40	2		capacitor bank-69kV	1	14
157	GLENDALE - GLENDALE	Transmission		230	12		100	2				
158	GOODYEAR	Distribution		69	35		120	2				
159	GRAND CANYON - GRAND CANYON	Distribution		69	12		9	1				
160	GRANITE CREEK - CHINO VALLEY	Transmission		69								
161	GRANITE REEF - SCOTTSDALE	Distribution		69	12		41	1				
162	GRAY MOUNTAIN - CAMERON	Distribution		69	22		1	2				
163	GREENBRIER - GLENDALE	Distribution		69	12		41	1				
164	GREENWAY - GLENDALE	Distribution		69	12		123	3		capacitor bank-12kV	3	11
165	GREY BEARS - CHINO VALLEY	Distribution		69	12		20	1				
166	GRISWOLD - PHOENIX	Distribution		69	12		41	1				
167	HAMBLIN - CAMERON	Distribution		69	12			1				
168	HANKS - N. OF FLAGSTAFF	Distribution		69	12			1				
169	HARBOR - PHOENIX	Distribution		69	12		123	3				
170	HARQUAHALA - TONOPAH	Distribution		69	12		20	1				
171	HASHKNIFE - HEBER	Transmission		69								
172	HATFIELD - PEORIA	Distribution		69	12		82	2				
173	HAVASU - PARKER	Distribution		69	12		20	1				

174	HAYDEN - HAYDEN	Distribution		21	7	4	10	1				
175	HAYES GULCH - GLOBE	Distribution		69	21		20	1				
176	HEARN - SURPRISE	Distribution		69	12		83	2		capacitor bank-69kV	1	14
177	HEDGEPETH HILLS - PHOENIX	Distribution		69	12		83	2		capacitor bank-69kV	1	29
178	HOHOKAM - PHOENIX	Distribution		69	12		20	1		capacitor bank-12kV	2	5
179	HONEYWELL - PHOENIX	Distribution		69	12		83	2				
180	HOODOO WASH - DATELAND	Transmission		525								
181	HORN - HORN	Distribution		69	12		10	1				
182	HOWARD MESA - WILLIAMS	Distribution		69	12			1				
183	HUMBUG - PEORIA	Distribution		69	12		40	2				
184	INDIAN BEND - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	2	7
185	INDIANOLA - PHOENIX	Distribution		69	12		123	3				
186	IVALON - YUMA	Distribution		69	12		40	2				
187	JACKSON STREET - PHOENIX	Distribution		69	12		123	3				
188	JAVELINA - SURPRISE	Distribution		69	12		83	2				
189	JOMAX - SCOTTSDALE	Distribution		69	12		41	1				
190	KACHINA - KACHINA VILLAGE	Distribution		69	12		10	1				
191	KAIBAB - WILLIAMS	Distribution		69	12		20	1				
192	KEAMS CANYON - W. OF KEAMS CANYON	Distribution		69	21		9	1				
193	KEARNY - KEARNY	Distribution		21								
194	KIRKLAND JUNCTION - SE.OF KIRKLAND	Distribution		69	12		9	1				
195	LAGUNA - SOMERTON	Distribution		69	12		36	2		capacitor bank-69kV	2	29
196	LE BARRON HILL - FLAGSTAFF	Distribution		69	7			1				
197	LEROUX - N. OF HOLBROOK	Distribution		69	12		20	1				
198	LEUPP JUNCTION - W. OF WINSLOW	Distribution		69	21		6	1				
199	LIBERTY IRON - PHOENIX	Transmission		69								
200	LINCOLN STREET SOUTH - PHOENIX	Transmission		230	69	12	188	1				
201	LINCOLN STREET NORTH - PHOENIX	Distribution		69	12		83	2		capacitor bank-69kV	1	35
202	LINCOLN STREET WEST - PHOENIX	Distribution		69	12		164	4		capacitor bank-12kV	8	19
203	LITCHFIELD - LITCHFIELD PARK	Distribution		69	12		83	2				
204	LOMA VISTA - PHOENIX	Distribution		69	12		83	2				
205	LONE PEAK - PHOENIX - T	Transmission		230	69	12	376	2				
206	LONE PEAK - PHOENIX - D	Distribution		69	12		41	1				
207	LONESOME VALLEY - PRESCOTT	Distribution		69	12		82	2				
208	LOOKOUT - PHOENIX	Distribution		69	12		83	2				

209	LOWER RIVER - PHOENIX	Distribution		69	4		16	2				
210	LUKE FIELD NORTH - LUKE AFB	Distribution		69	12		40	2				
211	MAGNOLIA - STANTON	Distribution		69	7			1				
212	MARINE AIR BASE - YUMA	Distribution		69	12		83	2		capacitor bank-12kV	2	5
213	MARINETTE - SUN CITY	Distribution		69	12		83	2				
214	MARTINEZ WASH - WICKENBURG	Distribution		69	7			1				
215	MAZATZAL - RYE - D	Distribution		69	21		20	1				
216	MAZATZAL - RYE - T	Transmission		345	69	12	150	1				
217	MCGUIREVILLE - RIM ROCK	Distribution		69	12		16	1				
218	MCCORMICK - SCOTTSDALE	Distribution		69	12		83	2				
219	MCDOWELL - PHOENIX	Distribution		69	12		83	2				
220	MCMICKEN - SURPRISE	Distribution		69	12		83	2				
221	MEADOWBROOK - PHOENIX - T	Transmission		230	69	12	188	1				
222	MEADOWBROOK - PHOENIX - D	Distribution		69	12		123	3		capacitor bank-69kV	1	48
223	MERIDIAN - GLENDALE	Transmission		69								
224	MERRILL - FLORENCE	Distribution		69	12		41	1		capacitor bank-69kV	2	14
225	METRO - PHOENIX	Distribution		69	12		125	3		capacitor bank-12kV	4	10
226	MIDTOWN - PHOENIX	Distribution		69	12		41	1		capacitor bank-12kV	2	10
227	MILLER WASH - VALLE	Distribution		69	7			1				
228	MILLIGAN - ELOY	Transmission		230	69	12	376	2				
229	MINGUS - JEROME	Distribution		69	7		1	2				
230	MITTRY - YUMA	Distribution		69	12		7	1				
231	MOENKOPI - CAMERON	Transmission		525						capacitor bank 525kV	4	2,041
232	MOENKOPI - CAMERON (sr)	Transmission		525						shunt reactor-525kV	11	816
233	MONTE CRISTO - PHOENIX	Distribution		69	12		83	2				
234	MOON VALLEY - PHOENIX	Distribution		69	12		83	2				
235	MORGAN - PEORIA	Transmission		525	230	35	600	1	1			
236	MORRISTOWN - MORRISTOWN	Distribution		69	12		9	1		capacitor bank-69kV	1	11
237	MOUNTAIN VIEW - SUN CITY	Distribution		69	12		83	2		capacitor bank-69kV	1	48
238	MT. FLOYD - SELIGMAN	Transmission		230	12		50	1				
239	MUMMY MOUNTAIN - PARADISE VALLEY	Distribution		69	12		83	2				
240	MUNDS PARK - S.OF FLAGSTAFF	Distribution		69	21		9	1				
241	MURAL - BISBEE - D	Distribution		69	12		9	1			4	10

										capacitor bank-12kV		
242	MURAL - BISBEE - T	Transmission		115	69	12	100	1	1			
243	NADASY - N. OF WILLIAMS	Distribution		69	7			1				
244	NAVAJO - PAGE (sr)	Transmission	Attended	525						shunt reactor-525kV	5	891
245	NAVAJO - PAGE (cb)	Transmission	Attended	525						capacitor bank-525kV	2	1,738
246	NAVAJO ARMY DEPOT - FLAGSTAFF	Distribution		69	12		6	1				
247	NEW RIVER - NEW RIVER	Distribution		69	12		20	1				
248	NEWMAN PARK - S. OF FLAGSTAFF	Distribution		69	7			1				
249	NORTH GILA - YUMA 525-230kv	Transmission		525	230	35	600		1	shunt reactor-525kV	2	381
250	NORTH GILA - YUMA 525-69kv	Transmission		525	69	35	509	6	1	capacitor bank-525kV	2	978
251	NORTH VALLEY - PHOENIX	Distribution		69	12		83	2				
252	OAK CREEK - OAK CREEK	Distribution		69	12		40	2		capacitor bank-12kV	2	5
253	OBERLIN TEMP - SURPRISE	Distribution		69	12		16	1				
254	OCOTILLO - TEMPE	Transmission	Attended	230	69	12	376	2		capacitor bank-230kV	2	314
255	OCOTILLO - TEMPE (cb)	Transmission	Attended	69						capacitor bank-69kV	1	48
256	OLD HOME MANOR - CHINO VALLEY	Transmission		69								
257	ORANGEWOOD - PHOENIX	Distribution		69	12		123	3				
258	ORMES - MAYER	Distribution		69	4		4	1				
259	OSBORNE TANK - FLAGSTAFF	Distribution		69	7			1				
260	OWEN - PAYSON	Distribution		69	21		20	1		capacitor bank-69kV	1	2
261	PADRE - FLAGSTAFF	Distribution		69	12			1				
262	PALM VALLEY - GOODYEAR - T	Transmission		230	69	12	376	2				
263	PALM VALLEY - GOODYEAR - D	Distribution		69	12		125	3				
264	PALOMA - W. OF GILA BEND	Distribution		69	12		20	1				
265	PALOMINAS -HEREFORD	Distribution		69	12		20	1				
266	PANDA - GILA BEND	Transmission	Attended	230								
267	PAPAGO BUTTE - SCOTTSDALE	Distribution		69	12		40	2				
268	PARADISE - PHOENIX	Distribution		69	12		123	3		capacitor bank-12kV	2	7
269	PARKS - PARKS	Distribution		69	12		5	1				
270	PATTERSON - OUT OF BUCKEYE	Distribution		69	12		16	1				
271	PATTON - OUT OF MORRISTON	Distribution		69	12		9	1				

272	PAULDEN - PAULDEN	Distribution		69	12		20	1				
273	PEBBLECREEK - GOODYEAR	Distribution		69	12		83	2				
274	PEORIA - PEORIA	Distribution		69	12		83	2				
275	PERRYVILLE - PERRYVILLE	Distribution		69	12		82	2		capacitor bank-69kV	1	2
276	PICKET - SUPERIOR	Transmission		115	12		13	1				
277	PIGLET - SNOWFLAKE	Distribution		69	7			1				
278	PIMA - GOODYEAR	Distribution		69	12		83	2				
279	PINAL - GLOBE - T	Transmission		115	69	21	84	1				
280	PINAL - GLOBE - D	Distribution		69	21		41	1				
281	PINE SPRINGS - W. OF WILLIAMS	Distribution		69	7			1				
282	PINK CLIFFS - HOLBROOK	Distribution		69	7			1				
283	PINNACLE PEAK - PHOENIX 525-230kv	Transmission		525	230	35	1872	3		shunt reactor 525kV	1	190
284	PINNACLE PEAK - PHOENIX 345-230kv	Transmission		345	230	14	2025	3				
285	PINNACLE PEAK - PHOENIX 230-69kv	Transmission		230	69	12	752	4		capacitor bank-230kV	3	159
286	PIONEER - PHOENIX	Distribution		69	12		125	3				
287	PLANET - NE. OF PARKER	Distribution		69	12		4	1				
288	PLEASANT - GLENDALE	Distribution		69	12		20	1				
289	POLAND JUNCTION - NW. OF MAYER	Distribution		69	12		9	1				
290	POLK - PHOENIX	Distribution		69	12		123	3		capacitor bank-69kV	1	14
291	POLK - PHOENIX (cb)	Distribution		69						capacitor bank-12kV	6	14
292	POLLOCK -CHINO VALLEY	Distribution		69	12		2	3				
293	POPLAR WASH - PEEPLES VALLEY	Distribution		69	7		1	1				
294	PREACHER CANYON - STAR VALLEY - T	Transmission		345	69	12	162	2				
295	PREACHER CANYON - STAR VALLEY - D	Distribution		69	22		16	1				
296	PRESCOTT CHINO WELLS - CHINO VALLEY 69-4	Distribution		69	4		3	3				
297	PRESCOTT CHINO WELLS - CHINO VALLEY 69-12	Distribution		69	12		9	1				
298	PRESCOTT CITY - PRESCOTT	Distribution		69	12		83	2				
299	PYRAMID PEAK - GLENDALE	Distribution		69	12		41	1				
300	QUAIL SPRINGS - SE. OF COTTONWOOD	Distribution		69	12		40	2		capacitor bank-69kV	2	22
301	QUARTZSITE - QUARTZSITE	Distribution		69	12		16	1		capacitor bank-69kV	2	7
302	QUECHAN - YUMA	Distribution		69	12		83	2				
303	RACEWAY - PEORIA	Transmission		230	69	12	188	1				
304	RAINBOW VALLEY - SE.OF BUCKEYE	Distribution		69	12		9	1				

305	RAINTREE - SCOTTSDALE	Distribution		69	12		123	3				
306	RAMON ASO - RED LAKE,N. OF WILLIAMS	Distribution		69	12		1	1				
307	RAWHIDE - SCOTTSDALE	Distribution		69	12		83	2				
308	REACH - SCOTTSDALE - T	Transmission		230	69	12	376	2		capacitor bank-69kV	1	48
309	REACH - SCOTTSDALE - D	Distribution		69	12		41	1				
310	RED LAKE - E. OF WILLIAMS	Distribution		69	21		4	1				
311	RED MOUNTAIN - PHOENIX	Distribution		69	12		82	2		capacitor bank-12kV	4	10
312	RED ROCK - RED ROCK	Transmission		115	12		50	1		capacitor bank-12kV	2	9
313	REDONDO - YUMA	Distribution		69	12		20	1				
314	REIDHEAD - SNOWFLAKE	Distribution		69	7			1				
315	RINCON - WICKENBURG	Distribution		69	7			1				
316	RIO SALADO - TEMPE	Distribution		69	12		83	2				
317	RIO VISTA - SUN CITY	Distribution		69	12		83	2				
318	RIVERSIDE - YUMA	Distribution		69	12		9	1				
319	ROAD RUNNER - PHOENIX	Distribution		69	12		83	2				
320	ROBBINS BUTTE - OUT OF BUCKEYE	Distribution		69	12		1	3				
321	ROCK SPRINGS - ROCK SPRINGS	Distribution		69	12		16	1				
322	ROGERS LAKE - SW. OF FLAGSTAFF	Distribution		69	7			1				
323	ROSE GARDEN - PHOENIX	Distribution		69	12		83	2				
324	ROUND VALLEY - KINGMAN	Transmission		230								
325	RUNWAY - GOODYEAR	Distribution		69	35		200	4				
326	SADDLE MOUNTAIN - W. OF TONOPAH	Distribution		69	12		20	1		capacitor bank-69kV	1	7
327	SADDLE MOUNTAIN - W. OF TONOPAH (cb)	Distribution		12						capacitor bank-12kV	4	5
328	SADDLEBROOK - ORACLE	Transmission		115								
329	SAGE VALLEY - VALLE	Distribution		69	12		1	1				
330	SAGUARO 525kV - RED ROCK	Transmission	Attended	525	115	35	1450	2		shunt reactor-525kV	3	125
331	SAGUARO 230kV - RED ROCK	Transmission	Attended	230	115	12	896	2	1			
332	SAGUARO 115kV - RED ROCK	Transmission	Attended	115	12		20		1	capacitor bank-115kV	2	49
333	SALOME - S.E. OF SALOME	Distribution		69	12		20	1		capacitor bank-69kV	2	7
334	SAN LUIS - SAN LUIS	Distribution		69	12		82	2		capacitor bank-69kV	1	7
335	SAN LUIS (MEXICO CONN.) - SAN LUIS	Distribution		69	35		20	1	1	capacitor bank-34.5kV	1	4
336	SAN MANUEL - SAN MANUEL 115-46kv	Transmission		115	46		65	4				

337	SAN MANUEL - SAN MANUEL 115-12kv	Transmission		115	12	2	60	2				
338	SAN PEDRO - W. OF DOUGLAS	Distribution		69	12		20	1				
339	SANDVIG - FLAGSTAFF	Distribution		69	12		60	3				
340	SANGUINETTI - YUMA	Transmission		69								
341	SANTA ROSA - SE. OF MARICOPA	Transmission		230	69	12	355	2		capacitor bank-230kV	2	94
342	SARIVAL - GOODYEAR	Distribution		69	12		83	2		capacitor bank-69kV	2	29
343	SCATTER WASH - PHOENIX	Transmission		230	69	12	186	1				
344	SEDONA - SEDONA	Distribution		69	12		40	2				
345	SHAW - PHOENIX	Distribution		69	12		83	2				
346	SHEA - SCOTTSDALE	Distribution		69	12		83	2				
347	SHERMAN STREET - PHOENIX	Distribution		69	12		83	2				
348	SHOW LOW - SHOW LOW	Distribution		69	12		40	2		capacitor bank-12kV	4	10
349	SHOW LOW - SHOW LOW (cb)	Distribution		69						capacitor bank-69kV	1	14
350	SHUMWAY - SHOW LOW	Distribution		69	12		9	1		capacitor bank-12kV	2	6
351	SHUMWAY - SHOW LOW (cb)	Distribution		69						capacitor bank-69kV	2	14
352	SKUNK CREEK - GLENDALE	Distribution		69	12		83	2				
353	SNOWFLAKE - SNOWFLAKE	Distribution		69	12		40	2				
354	SOLDIERS TRAIL - FLAGSTAFF	Distribution		69	12		20	1		capacitor bank-69kV	1	7
355	SONORA - SUPERIOR	Distribution		69	22		1	2				
356	SOUTH O'NEIL - YUMA	Transmission		69								
357	SPANISH GARDENS - SURPRISE	Distribution		69	12		83	2				
358	SPIDER WEB - FLAGSTAFF	Distribution		69	2			1				
359	STAGECOACH - SCOTTSDALE	Distribution		69	12		83	2				
360	STANTON - S. OF YARNELL	Distribution		69	7		1	1				
361	STARDUST - SUN CITY WEST	Distribution		69	12		83	2				
362	STRATUS - GOODYEAR	Distribution		69	35		100	2				
363	STOUT - PHOENIX	Distribution		69	12		83	2				
364	STRAWBERRY - STRAWBERRY	Distribution		69	21		9	1				
365	STURM RUGER - N. OF PRESCOTT 69-4kv	Distribution		69	4		5	3				
366	STURM RUGER - N. OF PRESCOTT 69-12kv	Distribution		69	12		20	1				
367	SUGARLOAF - SNOWFLAKE	Transmission		525	69	35	269	3	1	capacitor bank-69kV	1	14
368	SUN VALLEY PARKWAY - BUCKEYE 525kv	Transmission		525	230	35	600	1		shunt reactor-525kV	1	190
369	SUN VALLEY PARKWAY - BUCKEYE 230kv	Transmission		230	69	12	187	1				

370	SUNDOG - PRESCOTT	Distribution		69	12		40	2		capacitor bank-69kV	2	14
371	SUNNYSLOPE - PHOENIX	Transmission		230	69	14	167	1				
372	SUNNYSLOPE - PHOENIX 230-69kv	Transmission		230	69	12	188	1				
373	SUNNYSLOPE - PHOENIX 69kv	Distribution		69	12		83	2		capacitor bank-69kV	1	43
374	SUNSHINE - WINSLOW	Distribution		69	12		2	3				
375	SURPRISE - SURPRISE - T	Transmission		230	69	12	564	3		capacitor bank-69kV	1	53
376	SURPRISE - SURPRISE - D	Distribution		69	12		123	3				
377	SWITZER CANYON - FLAGSTAFF	Distribution		69	12		40	2				
378	SYCAMORE - DUGAS	Distribution		69	7			1				
379	TABLE MESA - NEW RIVER	Distribution		69	12			1				
380	TAPCO - E. OF CLARKDALE	Distribution		69	2			2				
381	TAT MOMOLI - CASA GRANDE	Transmission		230								
382	TEMPE - TEMPE	Distribution		69	12		123	3				
383	TENTH STREET - YUMA	Distribution		69	12		40	2				
384	THAYER - THAYER	Distribution		69	12		20	1		capacitor bank - 12kV	2	5
385	THIRTY-SECOND STREET - YUMA	Distribution		69	12		83	2				
386	THOMPSON PEAK - SCOTTSDALE	Distribution		69	12		83	2				
387	THORNTON - CASA GRANDE	Distribution		69	12		20	1				
388	TOLTEC - ELOY	Distribution		69	12		41	1		capacitor bank-69kV	2	14
389	TONALEA - TUBA CITY	Distribution		69	22		2	3				
390	TONOPAH - TONOPAH	Distribution		69	12		16	1		capacitor bank-69kV	1	10
391	TONTO - PAYSON	Distribution		69	21		40	2		capacitor bank-69kV	1	7
392	TONTO - PAYSON (cb)	Distribution								capacitor bank-21.6kV	4	10
393	TRILBY WASH - SURPRISE	Transmission		230	69	12	188	1				
394	TUBA CITY - TUBA CITY	Distribution		69	12		20	1		capacitor bank-12kV	2	6
395	TURF - PHOENIX	Distribution		69	12		83	2				
396	TUSAYAN -TUSAYAN	Distribution		69	12		9	1		capacitor bank-12kV	3	4
397	TUSAYAN -TUSAYAN (cb)	Distribution								capacitor bank-69kV	4	14
398	TUTHILL - BUCKEYE	Distribution		69	12		83	2				
399	TWENTY - THIRD STREET-PHOENIX	Distribution		69	12		83	2				
400	TWIN ARROWS - FLAGSTAFF	Transmission		69								

401	UNION HILLS - PHOENIX	Distribution		69	12		83	2				
402	UTTING - SE. OF BOUSE	Distribution		69	12		40	2		capacitor bank-69kV	2	7
403	UTTING - SE. OF BOUSE (cb)	Distribution								capacitor bank-12kV	4	5
404	VALENCIA - BUCKEYE	Distribution		69	12		40	2				
405	VALLE - WILLIAMS	Distribution		69	21		2	3				
406	VALLEY FARMS - FLORENCE - T	Transmission		115	69	12	188	1				
407	VALLEY FARMS - FLORENCE - D	Distribution		69	12		41	1		capacitor bank-69kV	1	7
408	VARNEY - SURPRISE	Distribution		69	12		83	2				
409	VERDE - CLARKDALE	Transmission		230	69	12	200	2		capacitor bank-69kV	4	29
410	VIA DONA - SCOTTSDALE	Distribution		69	12		82	2				
411	VICKSBURG - S. OF VICKSBURG JUNCTION	Distribution		69	12		20	1				
412	VISTA - CASA GRANDE	Distribution		69	12		83	2		capacitor bank-12kV	4	14
413	WADDELL - SURPRISE	Distribution		69	12		83	2				
414	WALDRIP - YUMA	Transmission		69								
415	WATSON - BUCKEYE	Distribution		69	12		83	2				
416	WELCH - ASHFORK	Distribution		69	2			1				
417	WELLFIELD - PRESCOTT VALLEY	Distribution		69	12		40	2				
418	WENDON TEMP - LA PAZ	Distribution		69	12		11	1				
419	WEST PARK - BUCKEYE	Distribution		69	12		40	2		capacitor bank-69kV	1	10
420	WEST PHOENIX - PHOENIX - T	Transmission		230	69	12	564	3		capacitor bank-69kV	1	35
421	WEST PHOENIX - PHOENIX - D	Distribution		69	12		83	2		capacitor bank-12kV	4	10
422	WESTBROOK - PEORIA	Distribution		69	12		41	1				
423	WESTWING - SUN CITY 525kv	Transmission		525	230	35	4500	9	4	capacitor bank-525kV	1	340
424	WESTWING - SUN CITY (cb)	Transmission		525						shunt reactor-525kV	3	571
425	WESTWING - SUN CITY 69kv	Distribution		69	12		41	1				
426	WESTWING - SUN CITY 230kv	Transmission		230	69	12	376	2		shunt reactor-230kV	2	212
427	WHITE SPAR - PRESCOTT	Distribution		69	12		40	2		capacitor bank-12kV	4	12
428	WHITE TANKS - AVONDALE	Transmission		230	69	12	564	3				
429	WHY - AJO	Distribution		69	22		10	1				
430	WICKENBURG - WICKENBURG	Distribution		69	12		40	2		capacitor bank-69kV	1	12
431	WILAHA - WILLIAMS	Distribution		69	7			1				

432	WILD BURRO - NEW RIVER	Distribution		69	7			1				
433	WILD FLOWER - GOODYEAR	Distribution		69	12		83	2				
434	WILHOIT - PRESCOTT	Distribution		69	12		3	1				
435	WILLIAMS - WILLIAMS 69-12kv	Distribution		69	12		9	1		capacitor bank-69kV	2	12
436	WILLIAMS - WILLIAMS 69-4kv	Distribution		69	4		6	1				
437	WILLIS - GOODYEAR	Distribution		69	12		41	1		capacitor bank-69kV	1	14
438	WILLOW LAKE - PRESCOTT 230-115kv	Transmission		230	115	12	166	2		shunt reactor-230kV	1	25
439	WILLOW LAKE - PRESCOTT 230-69kv	Transmission		230	69	12	376	2				
440	WINDMILL - SEDONA	Distribution		69	7		1	1				
441	WINONA - WINONA	Distribution		69	12		3	1				
442	WINSLOW - WINSLOW	Distribution		69	12		20	2				
443	WINTERSBURG - TONOPAH	Distribution		69	12		18	1				
444	WOODRUFF - HOLBROOK	Distribution		69	21		4	1				
445	WOODY MOUNTAIN - FLAGSTAFF	Distribution		69	12		20	1		capacitor bank-69kV	1	7
446	WUPATKI - FLAGSTAFF	Distribution		69	12			1				
447	YALE - PHOENIX	Distribution		69	12		83	2		capacitor bank-12kV	4	10
448	YARNELL - YARNELL	Distribution		69	12		9	1				
449	YAVAPAI - CHINO VALLEY 525kv	Transmission		525	230	12	672	2				
450	YAVAPAI - CHINO VALLEY 230kv	Transmission		230	69	12	100	1				
451	YORKSHIRE - PHOENIX	Distribution		69	12		20	1				
452	YOUNG'S CANYON - DONEY PARK	Transmission		345	69	12	150	1	1	capacitor bank-69kV	1	14
453	YUCCA - YUMA	Transmission		161	69	2	84	1	1	capacitor bank-69kV	1	25
454	YUMA PALMS TEMP - YUMA	Distribution		69	12		20	1				
455	ZENIFF - SNOWFLAKE	Transmission		69								
456	TotalDistributionSubstationMember			23,631	4,119	4	15,978	555	1		255	1,631
457	TotalGenerationSubstationMember			0	0	0	0	0	0		0	0
458	TotalTransmissionSubstationMember			27,121	6,661	990	31,908	144	19		85	11,863
459	Total			50,752	10,780	994	47,886	699	20		340	13,494

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

Statement of Co-Ownership as described in instruction #6, Page 427 and as noted on Page 426. None of the Co-Owners is an associated company

(A) Co-Ownership On:
Cedar Mountain
Cholla Switchyard
Hoodoo Wash
Four Corners Switchyard
Morgan Substation
Navajo Switchyard
North Gila
Pinnacle Peak
Westwing 525Kv Switchyard
Westwing 230Kv Switchyard

(1) Co-Owners of Cedar Mountain are Salt River Project, Tucson Electric Power Company, United States.
(2) Co-Owner of Cholla Switchyard is Pacificorp.
(3) Co-Owners of Hoodoo Wash are Imperial Irrigation District, San Deigo Gas & Electric
(4) Co-Owners of Four Corners Switchyard are Salt River Project, Four Corners Acquisition, Public Service Of New Mexico, Southern California Edison, and Tucson Electric Power Company.
(5) Co-Owner of Morgan Substation is Salt River Project
(6) Co-Owners of Navajo Switchyard are Salt River Project, Nevada Power Company, United States, Tucson Electric Power Company, and Los Angeles Department of Water and Power
(7) Co-Owners of North Gila Substation are San Diego Gas & Electric and Imperial Irrigation District
(8) Co-Owner of Pinnacle Peak 500Kv Substation and 230Kv North Substation is Salt River Project
(9) Co-Owners of Westwing 525Kv Switchyard are Salt River Project, El Paso Electric Company, Tucson Electric Power Company, Public Service Company of New Mexico, and United States.
(10) Co-Owners of Westwing 230Kv Switchyard are Salt River Project, El Paso Electric Company, Public Service Company of New Mexico, and United States.

(B) Expenses for the operation, maintenance, and rents are not segregated in the Company's books for each substation

(D) Substations that APS does not own the majority portion and is not operating agent are not listed on this report

(b) Concept: PrimaryVoltageLevel

VOLTAGE IS EXPRESSED IN KV

(c) Concept: SecondaryVoltageLevel

VOLTAGE IS EXPRESSED IN KV

(d) Concept: CapacityOfConversionApparatusAndSpecialEquipment

CAPACITY IS EXPRESSED IN MVAR

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Common stock dividends	Pinnacle West Capital Corporation	438	376,500,000
3	Share of estimated income taxes	Pinnacle West Capital Corporation	236	19,783,108
4	Share of withholding and payroll taxes	Pinnacle West Capital Corporation	236, 241, 408	(a)247,949,090
5	Share of pension and other post retirement benefits contributions	Pinnacle West Capital Corporation	228	99,140,000
6	Share of employee benefits (excluding pension and OPEB contributions)	Pinnacle West Capital Corporation	228.3,925,926	(b)171,419,756
7	Employee programs payroll deductions	Pinnacle West Capital Corporation	143, 232, 242	85,737,802
8	Shared services	Pinnacle West Capital Corporation	various	(c)38,224,858
9	Compensation paid in stock	Pinnacle West Capital Corporation	various	(d)21,560,880
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Equity Infusion	Pinnacle West Capital Corporation	207	150,000,000
22	VEBA (Benefits) Settlement	Pinnacle West Capital Corporation	128	24,110,491
23	Shared services	Pinnacle West Capital Corporation	various	14,470,140
24	Four Corners Shared Services - 4CA	Pinnacle West Capital Corporation	131	1,365
25	Shared services	El Dorado Investment Company	131	(26,410)
26	Shared services	Bright Canyon Energy Corporation	131	431,968
27	Active Union Medical Reimbursement	Pinnacle West Capital Corporation	131	14,584,969
42				

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/16/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Includes employer share of FICA allocated at 7%

(b) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Includes benefits allocated at 37% & injuries and damages allocated at 1%

(c) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Includes governance allocations at 98.6%

(d) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Includes governance allocations at 98.6%

XBRL Instance File
Visit Submission Details Screen

APS SCHEDULE E-9
FERC FORM 3-Q

Quarterly Period Ended
June 30, 2022

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Arizona Public Service Company	End of: 2022/ Q2

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

FERC FORM NO. 1/3-Q (ED. 03-07)

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER
Identification

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Arizona Public Service Company	End of: 2022/ Q2

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
400 North 5th Street, Phoenix, AZ 85004

05 Name of Contact Person	06 Title of Contact Person
Jose Esparza	Vice President Regulatory

07 Address of Contact Person (Street, City, State, Zip Code)
400 North 5th Street, Phoenix, AZ 85004

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
(602) 525-2198	(1) ☑ An Original (2) ☐ A Resubmission	08/26/2022

Quarterly Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Elizabeth A. Blankenship	/s/Elizabeth A. Blankenship	08/26/2022
02 Title		
VP Controller & CAO APS/PNW		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

List of Schedules

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules (Electric Utility)	2	
1	Important Changes During the Quarter	108	
2	Comparative Balance Sheet	110	
3	Statement of Income for the Quarter	114	
4	Statement of Retained Earnings for the Quarter	118	
5	Statement of Cash Flows	120	
6	Notes to Financial Statements	122	
7	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122a	
8	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
9	Electric Plant In Service and Accum Provision For Depr by Function	208	
10	Transmission Service and Generation Interconnection Study Costs	231	
11	Other Regulatory Assets	232	
12	Other Regulatory Liabilities	278	
13	Elec Operating Revenues (Individual Schedule Lines 300-301)	300	
14	Regional Transmission Service Revenues (Account 457.1)	302	None
15	Electric Prod, Other Power Supply Exp, Trans and Distrib Exp	324	
16	Electric Customer Accts, Service, Sales, Admin and General Expenses	325	
17	Transmission of Electricity for Others	328	
18	Transmission of Electricity by ISO/RTOs	331	None
19	Transmission of Electricity by Others	332	
20	Deprec, Depl and Amort of Elec Plant (403,403.1,404,and 405) (except Amortization of Acquisition Adjustments)	338	
21	Amounts Included in ISO/RTO Settlement Statements	397	
22	Monthly Peak Loads and Energy Output	399	
23	Monthly Transmission System Peak Load	400	
24	Monthly ISO/RTO Transmission System Peak Load	400a	None

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1 During the second quarter of 2022, the Maricopa County franchise renewal was approved and became effective on April 6, 2022. County franchises do not include the collection and payment of franchise fees.

2 None.

3 None.

4 None.

5

Distribution: None.
Transmission:
None.

6

Contractual Obligations

As of June 30, 2022, our fuel and purchased power and purchase obligation commitments have increased from the information provided in our 2021 Federal Energy Regulatory Commission ("FERC") Form 1. The increase is primarily due to new purchased power and energy storage commitments of approximately $1.2 billion. The majority of the changes relate to 2024 and thereafter. This amount includes approximately $500 million of commitments relating to a new purchased power lease contract that is included in our non-commenced lease discussion below.

At June 30, 2022, we have various lease arrangements that have been executed but have not yet commenced. These arrangements primarily relate to energy storage assets, with expected lease commencement dates ranging from September 2022 through June 2024, with terms expiring through May 2044. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $1.8 billion over the term of the arrangements. For additional information regarding our lease commitments see our 2021 FERC Form 1. Certain of these non-commenced lease agreements were previously expected to commence in June 2022; however, during the second quarter of 2022 due to delays impacting the leased asset's in-service date, the lease commencement date has been delayed from June 2022 to September 2022. APS is currently working with the lessor to determine if this revised lease commencement date will be achieved.

Other than the items described above, there have been no material changes, as of June 30, 2022, outside the normal course of business in contractual obligations from the information provided in our 2021 FERC Form 1. See Note 5 for discussion regarding changes in our short-term and long-term debt obligations.

Credit Facilities

At June 30, 2022, Arizona Public Service ("APS") had two $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings and the agreements include a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At June 30, 2022, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $515 million of outstanding commercial paper borrowings.

On December 17, 2020, the Arizona Corporation Commission ("ACC") issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power) and a long-term debt authorization of $7.5 billion. On April 6, 2022, APS filed an application with the ACC to increase the long-term debt limit under the terms required by APS from $7.5 billion to $8.0 billion (subject to appropriate regulatory treatment of Power Purchase Agreement ("PPA") lease agreements) and to continue its authorization of short-term debt granted in the 2020 financing order. This application is pending the ACC's review. APS cannot predict the outcome of this matter.

On January 6, 2022, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

See "Financial Assurances" in Note 10 for a discussion of other outstanding letters of credit.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of June 30, 2022, standby letters of credit totaled $0.2 million and expire in 2023. As of June 30, 2022, surety bonds expiring through 2023 totaled $0.3 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Authorizations

On December 17, 2020, the ACC issued a financing order, Decision No. 77853, in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). The financing order also approved, subject to specified parameters and procedures, an increase in APS's long-term debt authorization from $5.9 billion to $7.5 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs.

On April 6, 2022, APS filed an application with the ACC to increase the long-term debt limit under the terms required by APS from $7.5 billion to $8.0 billion (subject to appropriate regulatory treatment of PPA lease agreements) and to continue its authorization of short-term debt granted in the 2020 financing order. This application is pending the ACC's review. APS cannot predict the outcome of this matter.

APS's issuances of short-term debt are authorized by the ACC in its Decision No. 77853 and/or by Arizona Revised Statutes Section 40-302.D and the issuances of long-term debt are authorized by the ACC in its Decision No. 77853.

7 None.

8

The union and non-union annualized wage scale increases for active employees during 2022 as of June 12, 2022, were as follows:

	Type of Cost	Number of Increases	Annualized Costs
a.	Union Negotiated	1,140	$ 3,328,979
b.	Non-Union Base Salary Increases	3,950	12,550,137
c.	Special Increases	410	1,307,541
d.	Promotions	354	3,714,763
	Total	**5,854**	**$ 20,901,420**

COMMENTS:

a. There were general wage increases for the International Brotherhood of Electrical Workers ("IBEW") (averaging 3.0%) during second quarter.
b. The overall non-union employee merit budget was 3.0%. Actual merit adjustments ranged from 0% to 8.0% based upon an employee's performance and their pay position within the salary range. Merit pay awards were added to base pay.
c. Salary adjustments to base pay are awarded to non-union employees throughout the year in special instances.
d. Promotions were awarded to union and non-union employees due to changes in job functions or grade level changes.

9

Legal Proceedings

I. LITIGATION & ENVIRONMENTAL MATTERS

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high-level waste from January 1, 2007, through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2022.

APS has submitted seven claims pursuant to the terms of the August 18, 2014 settlement agreement, for seven separate time periods during July 1, 2011 through June 30, 2020. The DOE has approved and paid $111.8 million for these claims (APS's share is $32.5 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers (see "Cholla" below). On November 1, 2021, APS filed its eighth claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). On March 22, 2022, the DOE approved a payment of $12.1 million (APS's share is $3.5 million) and on April 19, 2022, APS received this payment.

Superfund and Other Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a "PRP"). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, the Environmental Protection Agency ("EPA") advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS later in 2022. APS's estimated costs related to this investigation and study are approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS's use, storage, and disposal of substances containing per-and polyfluoroalkyl ("PFAS") compounds at the Ocotillo power plant site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash ("SIBW") Superfund site. The SIBW Superfund site includes the APS Ocotillo power plant site. On April 29, 2022, APS filed its response to this information request. At the present time, we are unable to predict the outcome of this matter and expenditures related to this matter cannot be reasonably estimated.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance and the appeal is proceeding in the normal course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of June 30, 2022. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See "Four Corners SCR Cost Recovery" below for additional information.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on Four Corners Power Plant ("Four Corners"). EPA required the plant to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plant. Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred.

In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See "Cholla" below for information regarding future plans for Cholla and details related to the resulting regulatory asset and see "Four Corners SCR Cost Recovery" above regarding recovery of the Four Corners SCR project.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, including supporting the passage of new state legislation providing ADEQ with appropriate permitting authority for CCR under the state solid waste management program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits. The proposal remains pending.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019, to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's July 29, 2020, final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure was submitted to EPA on November 30, 2020 and is currently pending. If granted, this application would allow the continued disposal of CCR within Cholla's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025. This application will be subject to public comment and, potentially, judicial review. EPA began taking action on these applications in January 2022, deeming APS's application for the Cholla facility "complete." We expect to have a proposed decision from EPA regarding Cholla in 2023.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Generating Station ("Navajo Plant") disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations or cash flows.

EPA Climate Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. Thereafter, on June 30, 2022, the U.S. Supreme Court reversed the D.C. Circuit's ruling, holding that existing power plant carbon regulations on the scale of the CPP are not authorized by the federal Clean Air Act. While the Biden administration has nonetheless expressed an intent to continue its effort to regulate carbon emissions in this sector more aggressively under the Clean Air Act (consistent with the U.S. Supreme Court's June 30 ruling), we cannot at this time predict the outcome of pending EPA rulemaking proceedings related to the regulation of carbon emissions from existing power plants.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants, as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. The EAB denied the environmental group petition on September 30, 2020. While the environmental groups had filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit, on May 2, 2022, the parties to the litigation executed a settlement agreement. We do not anticipate that this agreement will have a material impact on our financial position, results of operations, or cash flows.

II. REGULATORY MATTERS

2019 Retail Rate Case

APS filed an application with the ACC on October 31, 2019 (the "2019 Rate Case") seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners SCR project that was the subject of a separate proceeding. See "Four Corners SCR Cost Recovery" below. It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the Tax Expense Adjustment Mechanism ("TEAM"). The proposed total annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	45.3 %	4.10 %
Common stock equity	54.7 %	10.15 %
Weighted-average cost of capital		7.41 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.030168 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- authorization to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- a number of proposed rate and program changes for residential customers, including:
  - a super off-peak period during the winter months for APS's time-of-use with demand rates;
  - additional $1.25 million in funding for APS's limited-income crisis bill program; and
  - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;
- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Plant (see "Navajo Plant" below).

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommended, among other things, (i) an $89.7 million revenue increase, (ii) an average annual customer bill increase of 2.7%, (iii) a return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) the recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) the recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommended, among other things, (i) a $20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, (i) a $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism ("AEM"), to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition ("CCT") plan related to the closure or future closure of coal-fired generation facilities, of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020 financials. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, and

The commitment of funds that would not be recoverable through rates of $23 million were recognized in our December 31, 2020 financials. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, and this amount was recognized in its December 31, 2021 financials.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%. The hearing concluded on March 3, 2021, and the post-hearing briefing concluded on April 30, 2021.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the Arizona Renewable Energy Standard and Tariff ("RES") adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation, and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20-basis point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. The appeal at the Arizona Court of Appeals is proceeding in the normal course. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m. but did not explicitly approve the 10 months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by April 1, 2022. On January 12, 2022, the ACC voted to extend the deadline until September 1, 2022, to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

Additionally, consistent with the 2019 Rate Case decision, as of April 2022, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) $3.33 million to the Navajo Nation; (ii) $500,000 to the Navajo County communities; and (iii) $1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i) $500,000 to the Navajo Nation for CCT; (ii) $1.1 million to the Navajo County Communities for CCT and economic development; and (iii) $1.25 million to the Hopi Tribe for CCT and economic development. The ACC has also authorized $1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservation. Expenditure of the recoverable funds for electrification of homes and businesses on the Navajo Nation and the Hopi reservations is contingent upon completion of a census of the unelectrified homes and businesses in each that are also within APS service territory.

APS expects to file an application with the ACC for its next general retail rate case by the end of October 2022, allowing for a test year ending June 30, 2022.

Information Technology ACC Investigation

On December 16, 2021, the ACC opened an investigation into various matters related to APS's Information Technology department, including information about technology projects, costs, vendor management leadership and decision making. APS is cooperating with the investigation. APS cannot predict the outcome of this matter.

2016 Retail Rate Case Filing

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules.

Other key provisions of the 2017 Settlement Agreement include the following:

- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing SCR equipment at Four Corners;
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the Power Supply Adjustor ("PSA") to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as "APS Solar Communities") for utility-owned solar distributed generation ("DG") with the purpose of expanding access to rooftop solar for low-and moderate-income Arizonans, recoverable through the RES, to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
  - a change in the on-peak time-of-use period from noon to 7 p.m. to 3 p.m. to 8 p.m. Monday through Friday, excluding holidays;
  - non-grandfathered DG customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
  - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027, for combined-cycle generating units), unless expressly authorized by the ACC.

On August 15, 2017, the ACC approved the 2017 Settlement Agreement without material modifications and on August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"). The new rates went into effect on August 19, 2017.

See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget. In 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program

authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2020. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2020. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 Demand Side Management Implementation Plan ("DSM Plan").

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its integrated resource plan ("IRP"), and seek cost recovery in a rate process. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source requests for proposals ("RFP") requirements and the IRP process. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget includes funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the 2019 Rate Case decision. APS's budget proposal supports existing approved projects and commitments and requests a waiver of the RES residential and non-residential distributed energy requirements for 2022. On May 18, 2022, the ACC approved the 2022 RES Implementation Plan, including an amendment requiring a stakeholder working group convene to develop a community solar program for the Commission's consideration at a future date.

In response to an ACC inquiry, the ACC Staff filed a report providing the history of APS's long-term purchased power contract of the 280 MW Concentrating Solar Power Plant. This report outlines alternative options that the ACC could pursue to address the costs of this contract, which was executed in February 2008. On July 13, 2022, the ACC approved an option to take no action at this time.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards ("EES") require APS to submit a DSM Plan annually for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its Lost Fixed Cost Recovery ("LFCR") mechanism. See below for discussion of the LFCR.

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the DSM portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan sought a requested budget of $52.6 million and requested a waiver of the EES for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels but kept the overall budget at $52.6 million.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption during the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, as described below.

On December 31, 2020, APS filed its 2021 DSM Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Plan that proposed an additional performance incentive for customers participating in the residential energy storage pilot program approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Plan.

On April 20, 2021, APS filed a request to extend the June 1, 2021 deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved the request, granting an extension until 120 days after the ACC action on the 2021 DSM Plan, or December 31, 2021, whichever is later. On December 17, 2021, APS filed its 2022 DSM Plan, which requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021. In March 2022, APS indicated that it intends to file its 2023 DSM Plan within 120 days after the ACC has taken action on APS's 2022 DSM Plan. The ACC has not yet ruled on the 2022 DSM Plan.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2022 and 2021 (dollars in thousands):

	Six Months Ended June 30,	
	2022	**2021**
Beginning balance	$ 388,148	$ 175,835
Deferred fuel and purchased power costs — current period	98,707	135,905
Amounts charged to customers	(96,842)	(10,828)
Ending balance	$ 390,013	$ 300,912

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh, which consisted of a forward component of $(0.002086) per kWh and a historical component of $0.001630 per kWh. The 2020 PSA rate is a $0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh, which consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the rate increase taking effect in April 2021, and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a rate of $0.003544 per kWh and consisted of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit to better understand the factors that contributed to the increase in fuel costs.

On April 1, 2022, the ACC filed a final report of its audit findings regarding APS's fuel and purchased power costs for the period January 2019 through January 2021. The report contains an in-depth review of APS's fuel and purchased power contracts, its monthly fuel accounting activities, its forecasting and dispatching procedures, and its monthly PSA filings, among other fuel-related activities. The report finds that the APS's fuel processing accounting practices, dispatching procedures, and procedures for hedging activity are reasonable and appropriate. The report includes several recommendations for the ACC's consideration, including review of current contracts, maintenance schedules, and certain changes and improvements to the schedules in APS's monthly PSA filings. APS cannot predict the future impacts, if any, of this audit.

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate is a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022. At the time of the compliance filing, the amount remaining over the annual cap was approximately $365 million of fuel and purchased power costs which will be reflected in future year resets of the PSA.

On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA, and on January 12, 2021, the ACC approved this application. On October 28, 2021, APS filed an application requesting approval to recover costs related to three additional energy storage projects through the PSA once the systems are in service, and on December 16, 2021, the ACC approved this application. On February 22, 2022, APS filed an application requesting similar recovery through the PSA for a solar plus energy storage project, and on April 13, 2022, the ACC approved this application. For each of these applications that have been approved by the ACC, the ACC has not ruled on prudency.

Environmental Improvement Surcharge ("EIS"). The EIS permits APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2022 application requested an increase in the charge to $11.4 million, or $1.1 million over the prior-period charge, and it became effective with the first billing cycle in April 2022.

Transmission Rates, Transmission Cost Adjustor ("TCA") and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the settlement agreement entered into in 2012 regarding APS's rate case ("2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. APS reviews the proposed formula rate filing amounts with the ACC Staff. Any items or adjustments which are not agreed to by APS and the ACC Staff can remain in dispute until settled or litigated with FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 17, 2020, APS made a filing to make modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Cuts and Job Act (the "Tax Act"), as well as for future local, state, and federal statutory tax rate changes. APS amended its March 17, 2020 filing on April 28, 2020, September 29, 2021, and October 27, 2021. In January 2022, FERC approved APS's modifications to its annual transmission formula.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the 12-month period beginning June 1, 2020, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Effective June 1, 2022, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $33 million for the 12-month period beginning June 1, 2022, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $6.4 million and retail customer rates would have decreased by approximately $26.6 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $2.4 million, resulting in a reduction to the residential rate and increases to commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2022.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential and 2.68 cents for lost non-residential kWh as set forth in the 2019 Rate Case decision. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment; thus, the previously approved rates continued to remain intact and the $11.8 million increase was reflected in APS's 2022 filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism, as a result of the 2019 Rate Case decision effective on December 1, 2021, did not materially impact its results of operations and financial statements for the year ended December 31, 2021. However, as a result of certain changes made to the LFCR mechanism in the 2019 Rate Case decision, the mechanism no longer qualified for alternative revenue program accounting treatment, which impacts the future timing of related revenue recognition.

On February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels, which was inclusive of the $11.8 million balance from the 2021 filing). On May 9, 2022, the ACC Staff filed its revised report and proposed order regarding APS's 2022 LFCR adjustment, concluding that APS calculated the adjustment in accordance with its Plan of Administration. On May 18, 2022, the ACC approved the 2022 LFCR adjustment, with a rate effective date of June 1, 2022.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On August 13, 2018, APS filed a request with the ACC that addressed the return of $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 were recorded as a part of the balancing account and were addressed for recovery as part of the 2019 Rate Case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit were recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which provided an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of the 2019 Rate Case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit were recognized based upon APS's seasonal kWh sales pattern.

As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021, and all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS's next rate case.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from residential DG solar facilities will be determined using a RCP methodology as determined in the ACC's generic Value and Cost of Distributed Generation docket. RCP is a method that is based on the most recent five-year rolling average price that APS incurs for utility-scale solar projects. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. The ACC is no longer pursuing development of a forecasted avoided cost methodology as an option for utilities in place of the RCP. Commercial customers, grandfathered residential solar customers, and residential customers with DG systems other than solar facilities continue to qualify for net metering.

In addition, the ACC made the following determinations in the Value and Cost of Distributed Generation docket:

- RCP customers who have interconnected a DG system or submitted an application for interconnection for DG systems will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility (for APS residential customers, as of September 1, 2017, based on APS's 2017 Rate Case Decision);
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an initial export price is set for utilities, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies.

In accordance with the 2017 Rate Case Decision, APS filed its request for a RCP export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021. On April 29, 2022, APS filed an application to decrease the RCP price to 8.46 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2022. On July 12, 2022, the ACC approved the RCP as filed.

See "2016 Retail Rate Case Filing" above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

After various proceedings between September 2016 and March 2020, at which time Burns' appeal of a prior dismissal by the trial court was pending before the Arizona Court of Appeals, Burns' position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. On March 4, 2021, the Court of Appeals found Burns' motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day.

In its March 4, 2021 opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021, requesting that the petition be denied. The Arizona Supreme Court granted Burns' petition and heard oral argument on March 8, 2022. Pinnacle West and APS cannot predict the outcome of this matter.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the IRP process. On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and subsequent drafts were filed by ACC Staff in July 2019, February 2020, and July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. A new EES was not included in the proposed rules. These rules would have required utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, these rules would have changed the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. During March and April 2022, the ACC reviewed several proposed amendments for a proposed all-source RFP and IRP rulemaking package but delayed a vote on the amendments to a future date. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS's IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by 2030 and authorizing future rate base treatment of qualifying demand-side resources as proposed in future rate cases. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year PPAs with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

On July 16, 2020, FERC issued a final rule revising FERC's regulations implementing PURPA. The final rule went into effect on December 31, 2020.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur and customers will have four months to pay back their deposit and any remaining delinquent amounts. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method (June 1 – October 15) for disconnection moratoriums. On November 2, 2021, the ACC approved the final rules, and on November 23, 2021, the rules were submitted to the Arizona Office of the Attorney General for final review and approval. The new rules became effective on April 18, 2022, and APS has employed the calendar method for its disconnection moratorium.

In accordance with the ACC service disconnection rules, APS now suspends the disconnection of customers for nonpayment from June 1 through October 15 each year ("Annual Disconnection Moratorium"). Customers with past due balances of $75 or greater as of the beginning of the Annual Disconnection Moratorium are automatically placed on six-month payment arrangements. In addition, APS voluntarily began waiving late payment fees of its customers ("Late Fee Waivers") on March 13, 2020. APS is continuing to apply Late Fee Waivers for residential customers; however, effective May 1, 2022, late payment fees for commercial and industrial customers were reinstated. Since the suspensions and moratoriums on disconnections began, APS has experienced an increase in bad debt expense and the related write-offs of delinquent customer accounts.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. In April 2022, the Arizona Legislature passed a bill that would nullify a 24-year-old electric deregulation law that has been in place since 1998. The bill was signed by the Arizona Governor and will take effect September 23, 2022. APS cannot predict what impact, if any, this change will have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates of convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which has been returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. The ACC did not issue a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Rate Case filing with the ACC.

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance and the appeal is proceeding in the normal course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of June 30, 2022. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See above for further discussion on the 2019 Rate Case decision.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of the Cholla Power Plant ("Cholla") and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if the EPA approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS has committed to end the use of coal at its remaining Cholla units by 2025.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $39.5 million as of June 30, 2022, in addition to a return on its investment. In accordance with generally accepted accounting principles ("GAAP"), in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allows for decommissioning activities to begin after the plant ceased operations. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset.

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant, $57.4 million as of June 30, 2022, in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset, $15.4 million as of June 30, 2022. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

10 None.

12 N/A

13 **Board and Officer Elections, Retirements, Resignations and Changes During the Second Quarter of 2022:**

Directors - Note - all of the Directors are voted on or reappointed in May.

Officers - Note - all of the Officers are re-elected in May.

- On May 6, 2022, Barbara Lockwood announced her retirement effective December 31, 2022.
- On May 11, 2022, Theodore Geisler was appointed President of APS effective May 16, 2022.
- On May 11, 2022, Andrew Cooper was appointed Senior Vice President & Chief Financial Officer effective May 16, 2022.
- On May 11, 2022, Jose Esparza, Vice President of Regulatory was named Interim Head of Public Policy effective May 16, 2022.
- On May 11, 2022, Paul Mountain became Vice President of Finance and Treasurer effective May 16, 2022.
- On May 23, 2022, Barbara Lockwood's title was changed to Executive Vice President & Advisor to the CEO effective same date.
- On May 23, 2022, Adam Heflin was appointed Executive Vice President and Chief Nuclear Officer effective June 6, 2022.
- On June 22, 2022, Maria Lacal announced her retirement date will be September 30, 2022. Her title was also changed to Executive Vice President & Advisor to the CEO effective same date.

14 N/A

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	24,268,362,807	23,785,603,245
3	Construction Work in Progress (107)	200	1,270,141,591	1,210,177,757
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		25,538,504,398	24,995,781,002
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	8,525,604,547	8,331,220,117
6	Net Utility Plant (Enter Total of line 4 less 5)		17,012,899,851	16,664,560,885
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	96,691,250	119,818,855
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		28,338,742	(1,683)
9	Nuclear Fuel Assemblies in Reactor (120.3)		229,719,432	239,162,171
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	125,362,528	133,121,924
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		229,386,896	225,857,419
14	Net Utility Plant (Enter Total of lines 6 and 13)		17,242,286,747	16,890,418,304
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		7,486,575	7,486,575
19	(Less) Accum. Prov. for Depr. and Amort. (122)		101,994	90,418
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		1,991,913,625	2,190,864,957
29	Special Funds (Non Major Only) (129)			

30	Long-Term Portion of Derivative Assets (175)		111,847,073	48,302,351
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,111,145,279	2,246,563,465
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		23,934,353	5,433,352
36	Special Deposits (132-134)			
37	Working Fund (135)		3,773,020	3,866,020
38	Temporary Cash Investments (136)		75,099	75,019
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		362,002,345	292,414,204
41	Other Accounts Receivable (143)		57,296,413	98,097,118
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		23,146,695	25,354,026
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		65,502	22,111
45	Fuel Stock (151)	227	20,116,220	10,380,456
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	367,947,319	349,405,026
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	9,711,066	7,651,066
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	3,707,966	(270,325)
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		74,019,651	66,246,118
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		234,523,143	133,980,067
62	Miscellaneous Current and Accrued Assets (174)		36,106,539	36,162,724

63	Derivative Instrument Assets (175)		289,612,337	115,079,746
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		111,847,073	48,302,351
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		1,347,897,205	1,044,886,325
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		46,173,278	47,861,489
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	1,669,520,022	1,690,573,528
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,834,797	3,337,037
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		1,734,432	532,444
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	34,143,567	29,659,130
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		10,227,272	11,019,871
82	Accumulated Deferred Income Taxes (190)	234	1,072,853,735	1,081,616,724
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		2,837,487,103	2,864,600,223
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		23,538,816,334	23,046,468,317

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	178,162,368	178,162,368
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		3,190,807,686	3,040,807,686
7	Other Paid-In Capital (208-211)	253	18,400,365	18,400,365
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	37,511,652	37,511,652
11	Retained Earnings (215, 215.1, 216)	118	3,472,402,859	3,470,235,012
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(36,221,360)	(34,880,386)
16	Total Proprietary Capital (lines 2 through 15)		6,786,040,266	6,635,213,393
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	35,975,000	35,975,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	6,310,253,679	6,310,576,738
22	Unamortized Premium on Long-Term Debt (225)		12,971,355	13,574,557
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		14,502,004	14,994,744
24	Total Long-Term Debt (lines 18 through 23)		6,344,698,030	6,345,131,551
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		885,042,872	913,109,063
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		1,122,216	741,979

29	Accumulated Provision for Pensions and Benefits (228.3)		186,755,794	189,520,109
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			1,394,062
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		784,471,609	767,382,593
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,857,392,491	1,872,147,806
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		515,000,000	278,700,000
38	Accounts Payable (232)		429,634,451	389,260,216
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		109,852,976	103,541,789
41	Customer Deposits (235)		41,458,993	42,292,969
42	Taxes Accrued (236)	262	217,720,292	178,311,609
43	Interest Accrued (237)		58,183,746	57,942,476
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		37,669	104,728
48	Miscellaneous Current and Accrued Liabilities (242)		159,761,934	139,378,781
49	Obligations Under Capital Leases-Current (243)		138,408,046	113,392,488
50	Derivative Instrument Liabilities (244)		4,053,483	7,478,043
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			1,394,062
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,674,111,590	1,309,009,037
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		336,198,398	257,151,039
57	Accumulated Deferred Investment Tax Credits (255)	266	184,032,381	186,569,907
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	324,521,243	304,515,263
60	Other Regulatory Liabilities (254)	278	2,597,270,544	2,713,540,369
61	Unamortized Gain on Reaquired Debt (257)		46,911	68,563

62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		2,578,407,673	2,566,397,208
64	Accum. Deferred Income Taxes-Other (283)		856,096,807	856,724,181
65	Total Deferred Credits (lines 56 through 64)		6,876,573,957	6,884,966,530
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		23,538,816,334	23,046,468,317

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	1,854,656,159	1,696,733,850	1,073,162,068	996,693,029	1,854,656,159	1,696,733,850				
3	Operating Expenses											
4	Operation Expenses (401)	320	932,811,871	754,866,649	526,351,252	412,037,889	932,811,871	754,866,649				
5	Maintenance Expenses (402)	320	100,476,241	111,470,542	53,536,917	55,031,040	100,476,241	111,470,542				
6	Depreciation Expense (403)	336	288,478,799	264,648,320	145,093,268	132,868,632	288,478,799	264,648,320				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	4,669,928	2,458,460	2,334,964	1,311,498	4,669,928	2,458,460				
8	Amort. & Depl. of Utility Plant (404-405)	336	54,989,092	48,585,643	26,797,821	23,462,178	54,989,092	48,585,643				
9	Amort. of Utility Plant Acq. Adj. (406)	336	5,436,722	5,436,722	2,718,361	2,718,361	5,436,722	5,436,722				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											

11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		17,712,935	15,670,298	8,647,272	8,003,895	17,712,935	15,670,298				
13	(Less) Regulatory Credits (407.4)			22,180,345		10,780,078		22,180,345				
14	Taxes Other Than Income Taxes (408.1)	262	125,152,340	133,346,758	60,526,831	66,667,906	125,152,340	133,346,758				
15	Income Taxes - Federal (409.1)	262	42,358,982	27,131,066	35,974,006	23,551,824	42,358,982	27,131,066				
16	Income Taxes - Other (409.1)	262	990,408	(395,725)	665,776	(49,007)	990,408	(395,725)				
17	Provision for Deferred Income Taxes (410.1)	234, 272	16,359,212	107,823,220	13,991,667	103,242,787	16,359,212	107,823,220				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	22,280,925	83,675,631	18,551,476	76,631,338	22,280,925	83,675,631				
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		12,521	13,613	7,099	7,614	12,521	13,613				
23	Losses from Disposition of Allowances (411.9)		12,626	13,983	6,806	7,356	12,626	13,983				
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,567,155,710	1,365,186,347	858,086,366	741,435,329	1,567,155,710	1,365,186,347				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		287,500,449	331,547,503	215,075,702	255,257,700	287,500,449	331,547,503				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,035,976	1,259,302	460,003	1,019,251						
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		569,999	1,211,931	136,358	1,055,109						
33	Revenues From Nonutility Operations (417)											
34	(Less) Expenses of Nonutility Operations (417.1)		11,576	37,195	5,788	19,475						
35	Nonoperating Rental Income (418)		53,042	37,525	761	36,537						
36	Equity in Earnings of Subsidiary Companies (418.1)	119										

37	Interest and Dividend Income (419)		2,494,672	2,527,551	1,395,276	1,046,625						
38	Allowance for Other Funds Used During Construction (419.1)		21,832,767	19,196,967	12,085,841	9,989,590						
39	Miscellaneous Nonoperating Income (421)		238,805,700	123,930,006	163,981,112	73,396,746						
40	Gain on Disposition of Property (421.1)		2,188,798	4,811,904	948,195	3,754,612						
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		265,829,380	150,514,129	178,729,042	88,168,777						
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		640,087	6,236,971	248,380	3,037,400						
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		464,291	1,518,853	176,370	(52,989)						
46	Life Insurance (426.2)											
47	Penalties (426.3)		132,000	35	132,000	35						
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,429,594	1,378,189	703,650	700,371						
49	Other Deductions (426.5)		242,832,043	108,327,247	166,452,631	66,512,274						
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		245,498,015	117,461,295	167,713,031	70,197,091						
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	289,675	279,604	144,649	142,565						
53	Income Taxes-Federal (409.2)	262	(3,134,299)	3,703,823	(1,893,415)	1,940,015						
54	Income Taxes-Other (409.2)	262	(697,012)	917,161	(410,560)	494,689						
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	3,207,218	39,579	1,900,428	33,480						
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	123,546	1,024,900	73,207	866,964						
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)		2,537,526	3,651,233	2,218,814	3,121,870						
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(2,995,490)	264,034	(2,550,919)	(1,378,085)						
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		23,326,855	32,788,800	13,566,930	19,349,771						
61	Interest Charges											
62	Interest on Long-Term Debt (427)		118,871,332	113,841,814	59,437,873	56,898,568						

63	Amort. of Debt Disc. and Expense (428)		2,180,952	1,988,206	1,090,476	993,007						
64	Amortization of Loss on Reaquired Debt (428.1)		792,598	838,379	396,299	412,306						
65	(Less) Amort. of Premium on Debt-Credit (429)		603,203	603,203	301,602	301,601						
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		21,652	21,652	10,826	10,826						
67	Interest on Debt to Assoc. Companies (430)											
68	Other Interest Expense (431)		5,550,548	3,451,618	3,748,090	2,070,930						
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,111,118	10,192,747	5,688,870	5,199,092						
70	Net Interest Charges (Total of lines 62 thru 69)		116,659,457	109,302,415	58,671,440	54,863,292						
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		194,167,847	255,033,888	169,971,192	219,744,179						
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		194,167,847	255,033,888	169,971,192	219,744,179						

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		3,470,235,012	3,216,954,483
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		194,167,847	255,033,888
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1		234	(192,000,000)	(187,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(192,000,000)	(187,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,472,402,859	3,284,988,371
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			

47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,472,402,859	3,284,988,371
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	194,167,847	255,033,888
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	293,148,727	267,108,674
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of UTL PLT; ACQ; ADJ; Prop Loss; Reg Study; Nuclear Fuel	109,921,234	81,372,126
5.2	Deferred Fuel and Purchased Power	(1,868,200)	(125,077,849)
8	Deferred Income Taxes (Net)	(2,838,041)	23,162,268
9	Investment Tax Credit Adjustment (Net)	(2,537,526)	(3,651,233)
10	Net (Increase) Decrease in Receivables	(132,154,956)	(133,684,933)
11	Net (Increase) Decrease in Inventory	(32,256,348)	(30,216,985)
12	Net (Increase) Decrease in Allowances Inventory	(2,060,000)	(1,233,050)
13	Net Increase (Decrease) in Payables and Accrued Expenses	108,242,510	63,750,894
14	Net (Increase) Decrease in Other Regulatory Assets	13,750,551	(22,135,078)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(256,138,914)	58,742,456
16	(Less) Allowance for Other Funds Used During Construction	21,832,767	19,196,967
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other Current Assets	(337,932)	(917,453)
18.2	Income Tax Receivable	10,755,546	
18.3	Prepaids	(18,529,078)	(3,236,492)
18.4	Risk Management	77,277	265,304
18.5	Other Current Liabilities	(96,030)	(166,248)
18.6	Accrued Taxes	39,408,684	44,438,615

18.7	Arizona Attorney General Settlement	(223,022)	(24,194,208)
18.8	Community Coal Transition - ST	(2,350,000)	
18.9	Customer Deposits	(833,976)	(3,921,064)
18.10	Employee Benefits	(1,736,812)	(4,063,714)
18.11	Exchange	(10,227)	(6,611,665)
18.12	Four Corners Take or Pay	(5,077,397)	(8,460,860)
18.13	Interest Accrued	241,270	56,702
18.14	Payroll Accrual	(13,341,089)	(8,246,449)
18.15	SCE Right of Way	644,518	3,490,500
18.16	Software License Agreements		1,509,470
18.17	Unbilled Revenue	1,878,210	1,690,691
18.18	Uncertain Tax Position Current Liabilities		408,015
18.19	Operating Leases	23,363,280	22,066,543
18.20	Other Long Term Assets/Liabilities Net		
18.21	Active Union Medical Trust	10,433,963	1,923,249
18.22	Asset retirement obligations expenditures	(3,314,000)	(3,174,000)
18.23	Carbon Allowance	1,800,159	1,356,527
18.24	Collateral	40,695,000	
18.25	Community Coal Transition - LT	(500,000)	100,000
18.26	Coal Reclamation	2,319,447	2,259,423
18.27	Coal Reclamation Escrow	1,054,532	(54,728)
18.28	Customer advances for construction	79,047,359	26,498,981
18.29	Decommissioning Trust	219,809,407	(83,512,526)
18.30	Information Systems Maintenance	(3,351,218)	3,301,904
18.31	Interconnection Deposits	598,457	
18.32	Interconnection Study	10,572,035	8,782,704
18.33	Long Term Operating Leases	(27,470,000)	(30,996,492)
18.34	Operating Lease - Right of Use Assets	29,613,000	34,756,761
18.35	Pension and other benefits	(2,954,000)	(978,000)
18.36	Postretirement assets	(43,853,602)	(52,013,302)
18.37	Retention Accrual	7,128,591	3,848,039
18.38	Software License Agreements - LT	(1,509,470)	1,509,470
18.39	Utility Plant (Removal Costs)	(28,014,087)	(40,640,848)

18.40	Other Long-Term Assets/Liabilities Net	(2,088,953)	2,896,628
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	591,393,959	303,945,688
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(728,816,912)	(648,601,134)
27	Gross Additions to Nuclear Fuel	(35,554,955)	(24,472,553)
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	10,111,118	10,192,747
31	Other (provide details in footnote):		
31.1	Contributions in Aid of Construction	68,306,000	31,533,000
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(706,176,985)	(651,733,434)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables	573,722	571,331
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	(61,624,147)	(7,986,223)
53	Other (provide details in footnote):		
53.1	Proceeds from Trust and Other Special Use Funds Sales (a)	692,186,134	587,841,774
53.2	Investment in Trust and Other Special Use Funds (a)	(692,811,236)	(588,982,273)
53.3	Other (provide details in footnote):		
53.4	Investments and Other Assets		
53.5	Post-Employment Benefits	(21,092)	(960,966)
53.6	Restricted Cash Investments	(298,643)	2,826,265

53.7	Other Assets	886,369	1,121,633
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(767,285,878)	(657,301,893)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Equity Infusion from Pinnacle West	150,000,000	
66	Net Increase in Short-Term Debt (c)	236,300,000	495,000,000
67	Other (provide details in footnote):		
67.1	Short-term debt borrowings under revolving credit facility		
67.2	Short-term debt repayments under revolving credit facility		
70	Cash Provided by Outside Sources (Total 61 thru 69)	386,300,000	495,000,000
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(192,000,000)	(187,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	194,300,000	308,000,000
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	18,408,081	(45,356,205)
88	Cash and Cash Equivalents at Beginning of Period	9,374,391	57,310,304
90	Cash and Cash Equivalents at End of Period	27,782,472	11,954,099

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

1. Other Comprehensive Basis of Accounting

The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). The primary differences in the accompanying FERC financial statements as compared to GAAP include presenting certain decommissioning and reclamation activities, deferred tax assets and liabilities, regulatory assets and liabilities and risk management assets and liabilities on a gross versus net basis; presenting cost of removal liabilities in accumulated provision for depreciation; presenting tax liabilities related to uncertain tax positions as deferred income tax liabilities; presenting intangible assets in net utility plant; deconsolidating certain Variable Interest Entities ("VIE") and presenting debt issuance costs in deferred debits rather than as a reduction of long-term debt. Additionally, the accompanying FERC financial statements do not separately present the current portion of such items as long-term debt, Asset Retirement Obligations ("ARO") and regulatory assets and liabilities as required by GAAP.

Arizona Public Service's ("APS") notes to financial statements have been combined with Pinnacle West Capital Corporation's financial statements and are prepared in accordance with GAAP; accordingly, certain footnotes are not reflective of APS's financial statements contained herein.

2. Summary of Significant Accounting Policies

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Our unaudited financial statements reflect all adjustments (consisting only of normal recurring adjustments except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations and cash flows for the periods presented. These statements and notes should be read in conjunction with the financial statements and related notes included in our 2021 FERC Form 1.

Allowance for Funds Used During Construction

On June 30, 2020, FERC issued an order granting a waiver request related to the existing Allowance for Funds Used During Construction ("AFUDC") rate calculation beginning March 1, 2020, through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. On September 21, 2021, it was further extended until March 31, 2022. The order provided a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS adopted this simplified approach to computing the AFUDC composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacted the AFUDC composite rate in 2021 and for the three-month period ended March 31, 2022. Furthermore, the change in the composite rate calculation did not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements. See Note 2 in our 2021 Form 1 for information on the accounting treatment for AFUDC.

Cash and Cash Equivalents

We consider cash equivalents to be highly liquid investments with a remaining maturity of three months or less at acquisition.

The following table summarizes supplemental APS cash flow information (dollars in thousands):

	Six Months Ended June 30, 2022	2021
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ (25)	$ 3,317
Interest, net of amounts capitalized	114,069	107,044
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 106,033	$ 105,515
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	7,512	248,694

Dividends accrued but not yet paid	96,000	93,500

Subsequent Events

Management evaluates events or transactions that occur after the balance sheet date, but before the financial statements are issued or available to be issued for potential recognition or disclosures in the financial statements as required by GAAP. We have evaluated subsequent events for recognition in the financial statements through August 3, 2022, which is the date the financial statements, prepared in accordance with GAAP were issued. Management updated such evaluation for disclosure purposes through August 26, 2022. The accompanying statements contain all adjustments and disclosures necessary for fair presentation.

3. Quarterly Fluctuations

Significant seasonal fluctuations in our revenues are due to the effects of seasonal temperature variations on energy consumption, timing of maintenance on electric generating units, and other factors. For these reasons, amounts reported in interim periods are not necessarily indicative of amounts expected for the respective annual period.

4. Revenue

Sources of Revenue

The following table provides detail of revenue disaggregated by revenue sources (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Retail Electric Service				
Residential	$ 537,589	$ 531,717	$ 904,935	$ 872,555
Non-Residential	462,669	420,995	822,185	735,778
Wholesale Energy Sales	42,729	19,229	71,419	41,698
Transmission Services for Others	29,426	22,575	54,912	41,558
Other Sources	750	2,177	1,206	5,145
Total operating revenues	$ 1,073,162	$ 996,693	$ 1,854,656	$ 1,696,734

Retail Electric Revenue. Retail electric revenue is generated by the sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the Arizona Corporate Commission ("ACC") and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 21 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms.

Wholesale Energy Sales and Transmission Services for Others. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities primarily consist of managing fuel and purchased power risks in connection with the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the three and six months ended June 30, 2022 were $1,075 million and $1,845 million, respectively, and for the three and six months ended June 30, 2021 were $977 million and $1,663 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the three and six months ended June 30, 2022, our revenues that do not qualify as revenue from contracts with customers were $(2) million and $10 million, respectively, and for the three and six months ended June 30, 2021 were $20 million and $34 million, respectively. This amount includes revenues related to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 6 for a discussion of our regulatory cost recovery mechanisms.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Comparative Balance Sheets as of June 30, 2022 or December 31, 2021.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. We continue to monitor the impacts of COVID-19, our disconnection policies, payment arrangements, among other considerations impacting our estimated write-off factor and allowance for doubtful accounts.

The following table provides a rollforward of the allowance for doubtful accounts (dollars in thousands):

	June 30, 2022	December 31, 2021
Allowance for doubtful accounts, balance at beginning of period	$ 25,354	$ 19,782
Bad debt expense	8,119	22,251
Actual write-offs	(10,326)	(16,679)
Allowance for doubtful accounts, balance at end of period	$ 23,147	$ 25,354

5. Long-Term Debt and Liquidity Matters

APS maintains committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

At June 30, 2022, APS had two $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings and the agreements include a sustainability- linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At June

environmental and employee health and safety commitments objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $500 million commercial paper program, for cash borrowings or for issuances of letters of credit. At June 30, 2022, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $515 million of outstanding commercial paper borrowings.

On December 17, 2020, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power) and a long-term debt authorization of $7.5 billion. On April 6, 2022, APS filed an application with the ACC to increase the long-term debt limit under the terms required by APS from $7.5 billion to $8.0 billion (subject to appropriate regulatory treatment of Power Purchase Agreement ("PPA") lease agreements) and to continue its authorization of short-term debt granted in the 2020 financing order. This application is pending the ACC's review. APS cannot predict the outcome of this matter.

On January 6, 2022, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

See "Financial Assurances" in Note 10 for a discussion of other outstanding letters of credit.

Debt Fair Value

Our long-term debt fair value estimates are classified within Level 2 of the fair value hierarchy. The following table presents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of June 30, 2022		As of December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total	$ 6,344,698	$ 5,518,483	$ 6,345,132	$ 6,964,196

6. Regulatory Matters

2019 Retail Rate Case

APS filed an application with the ACC on October 31, 2019 (the "2019 Rate Case") seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners Power Plant ("Four Corners") selective catalytic reduction ("SCR") project that was the subject of a separate proceeding. See "Four Corners SCR Cost Recovery" below. It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the Tax Expense Adjustment Mechanism ("TEAM"). The proposed total annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure		Cost of Capital	
Long-term debt	45.3	%	4.10	%
Common stock equity	54.7	%	10.15	%
Weighted-average cost of capital			7.41	%

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.030168 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- authorization to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- a number of proposed rate and program changes for residential customers, including:
  - a super off-peak period during the winter months for APS's time-of-use with demand rates;
  - additional $1.25 million in funding for APS's limited-income crisis bill program; and
  - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;
- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Generating Station (the "Navajo Plant") (see "Navajo Plant" below).

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommended, among other things, (i) an $89.7 million revenue increase, (ii) an average annual customer bill increase of 2.7%, (iii) a return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) the recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) the recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommended, among other things, (i) a $20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, (i) a $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism ("AEM"), to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition ("CCT") plan related to the closure or future closure of coal-fired generation facilities, of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020 financials. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, and this amount was recognized in its December 31, 2021 financials.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%. The hearing concluded on March 3, 2021, and the post-hearing briefing concluded on April 30, 2021.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the

recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the Arizona Renewable Energy Standard and Tariff ("RES") adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation, and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20 basis point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. The appeal at the Arizona Court of Appeals is proceeding in the normal course. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m. but did not explicitly approve the 10 months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by April 1, 2022. On January 12, 2022, the ACC voted to extend the deadline until September 1, 2022, to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

Additionally, consistent with the 2019 Rate Case decision, as of April 2022, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) $3.33 million to the Navajo Nation; (ii) $500,000 to the Navajo County communities; and (iii) $1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i) $500,000 to the Navajo Nation for CCT; (ii) $1.1 million to the Navajo County Communities for CCT and economic development; and (iii) $1.25 million to the Hopi Tribe for CCT and economic development. The ACC has also authorized $1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservation. Expenditure of the recoverable funds for electrification of homes and businesses on the Navajo Nation and the Hopi reservations is contingent upon completion of a census of the unelectrified homes and businesses in each that are also within APS service territory.

APS expects to file an application with the ACC for its next general retail rate case by the end of October 2022, allowing for a test year ending June 30, 2022.

Information Technology ACC Investigation

On December 16, 2021, the ACC opened an investigation into various matters related to APS's Information Technology department, including information about technology projects, costs, vendor management leadership and decision making. APS is cooperating with the investigation. APS cannot predict the outcome of this matter.

2016 Retail Rate Case Filing

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules.

Other key provisions of the 2017 Settlement Agreement include the following:

- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing SCR equipment at the Four Corners;
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the Power Supply Adjustor ("PSA") to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as "APS Solar Communities") for utility-owned solar distributed generation ("DG") with the purpose of expanding access to rooftop solar for low-and moderate-income Arizonans, recoverable through the RES, to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
    - a change in the on-peak time-of-use period from noon to 7 p.m. to 3 p.m. to 8 p.m. Monday through Friday, excluding holidays;
    - non-grandfathered DG customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
    - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027, for combined-cycle generating units), unless expressly authorized by the ACC.

On August 15, 2017, the ACC approved the 2017 Settlement Agreement without material modifications and on August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"). The new rates went into effect on August 19, 2017.

See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget. In 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2020. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2020. In addition, the ACC approved the implementation of a new pilot program that

incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 Demand Side Management Implementation Plan ("DSM Plan").

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its Integrated Resource Planning ("IRP"), and seek cost recovery in a rate process. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source requests for proposals ("RFP") requirements and the IRP process. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget includes funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the 2019 Rate Case decision. APS's budget proposal supports existing approved projects and commitments and requests a waiver of the RES residential and non-residential distributed energy requirements for 2022. On May 18, 2022, the ACC approved the 2022 RES Implementation Plan, including an amendment requiring a stakeholder working group convene to develop a community solar program for the Commission's consideration at a future date.

In response to an ACC inquiry, the ACC Staff filed a report providing the history of APS's long-term purchased power contract of the 280 MW Concentrating Solar Power Plant. This report outlines alternative options that the ACC could pursue to address the costs of this contract, which was executed in February 2008. On July 13, 2022, the ACC approved an option to take no action at this time.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Plan annually for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its Lost Fixed Cost Recovery ("LFCR") mechanism. See below for discussion of the LFCR.

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the DSM portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan sought a requested budget of $52.6 million and requested a waiver of the Electric Energy Efficiency Standard for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels but kept the overall budget at $52.6 million.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption during the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, as described below.

On December 31, 2020, APS filed its 2021 DSM Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Plan that proposed an additional performance incentive for customers participating in the residential energy storage pilot program approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Plan.

On April 20, 2021, APS filed a request to extend the June 1, 2021 deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved the request, granting an extension until 120 days after the ACC action on the 2021 DSM Plan, or December 31, 2021, whichever is later. On December 17, 2021, APS filed its 2022 DSM Plan, which requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021. In March 2022, APS indicated that it intends to file its 2023 DSM Plan within 120 days after the ACC has taken action on APS's 2022 DSM Plan. The ACC has not yet ruled on the 2022 DSM Plan.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2022 and 2021 (dollars in thousands):

	Six Months Ended June 30,	
	2022	2021
Beginning balance	$ 388,148	$ 175,835
Deferred fuel and purchased power costs - current period	98,707	135,905
Amounts charged to customers	(96,842)	(10,828)
Ending balance	$ 390,013	$ 300,912

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh, which consisted of a forward component of $(0.002086) per kWh and a historical component of $0.001630 per kWh. The 2020 PSA rate is a $0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh, which consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the rate increase taking effect in April 2021, and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a rate of $0.003544 per kWh and consisted of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit to better understand the factors that contributed to the increase in fuel costs.

On April 1, 2022, the ACC filed a final report of its audit findings regarding APS's fuel and purchased power costs for the period January 2019 through January 2021. The report contains an in-depth review of APS's fuel and purchased power contracts, its monthly fuel accounting activities, its forecasting and dispatching procedures, and its monthly PSA filings, among other fuel-related activities. The report finds that the APS's fuel processing accounting practices, dispatching procedures, and procedures for hedging activity are reasonable and appropriate. The report includes several recommendations for the ACC's consideration, including review of current contracts, maintenance schedules, and certain changes and improvements to the schedules in APS's monthly PSA filings. APS cannot predict the future impacts, if any, of this audit.

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate is a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022. At the time of the compliance filing, the amount remaining over the annual cap was approximately $365 million of fuel and purchased power costs which will be reflected in future year resets of the PSA.

On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA, and on January 12, 2021, the ACC approved this application. On October 28, 2021, APS filed an application requesting approval to recover costs related to three additional energy storage projects through the PSA once the systems are in service, and on December 16, 2021, the ACC approved this application. On February 22, 2022, APS filed an application requesting

similar recovery through the PSA for a solar plus energy storage project, and on April 13, 2022, the ACC approved this application. For each of these applications that have been approved by the ACC, the ACC has not ruled on prudency.

Environmental Improvement Surcharge ("EIS"). The EIS permits APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2022 application requested an increase in the charge to $11.4 million, or $1.1 million over the prior-period charge, and it became effective with the first billing cycle in April 2022.

Transmission Rates, Transmission Cost Adjustor ("TCA") and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the settlement agreement entered into in 2012 regarding APS's rate case ("2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. APS reviews the proposed formula rate filing amounts with the ACC Staff. Any items or adjustments which are not agreed to by APS and the ACC Staff can remain in dispute until settled or litigated with FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 17, 2020, APS made a filing to make modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Cuts and Job Act (the "Tax Act"), as well as for future local, state, and federal statutory tax rate changes. APS amended its March 17, 2020 filing on April 28, 2020, September 29, 2021, and October 27, 2021. In January 2022, FERC approved APS's modifications to its annual transmission formula.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the 12-month period beginning June 1, 2020, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Effective June 1, 2022, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $33 million for the 12-month period beginning June 1, 2022, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $6.4 million and retail customer rates would have decreased by approximately $26.6 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $2.4 million, resulting in a reduction to the residential rate and increases to commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2022.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential and 2.68 cents for lost non-residential kWh as set forth in the 2019 Rate Case decision. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment; thus, the previously approved rates continued to remain intact and the $11.8 million increase was reflected in APS's 2022 filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism, as a result of the 2019 Rate Case decision effective on December 1, 2021, did not materially impact its results of operations and financial statements for the year ended December 31, 2021. However, as a result of certain changes made to the LFCR mechanism in the 2019 Rate Case decision, the mechanism no longer qualified for alternative revenue program accounting treatment, which impacts the future timing of related revenue recognition.

On February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels, which was inclusive of the $11.8 million balance from the 2021 filing). On May 9, 2022, the ACC Staff filed its revised report and proposed order regarding APS's 2022 LFCR adjustment, concluding that APS calculated the adjustment in accordance with its Plan of Administration. On May 18, 2022, the ACC approved the 2022 LFCR adjustment, with a rate effective date of June 1, 2022.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On August 13, 2018, APS filed a request with the ACC that addressed the return of $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 were recorded as a part of the balancing account and were addressed for recovery as part of the 2019 Rate Case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit were recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which provided an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of the 2019 Rate Case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit were recognized based upon APS's seasonal kWh sales pattern.

As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021, and all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS's next rate case.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from residential DG solar facilities will be determined using a RCP methodology as determined in the ACC's generic Value and Cost of Distributed Generation docket. RCP is

a method that is based on the most recent five-year rolling average price that APS incurs for utility-scale solar projects. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. The ACC is no longer pursuing development of a forecasted avoided cost methodology as an option for utilities in place of the RCP. Commercial customers, grandfathered residential solar customers, and residential customers with DG systems other than solar facilities continue to qualify for net metering.

In addition, the ACC made the following determinations in the Value and Cost of Distributed Generation docket:

- RCP customers who have interconnected a DG system or submitted an application for interconnection for DG systems will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility (for APS residential customers, as of September 1, 2017, based on APS's 2017 Rate Case Decision);
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an initial export price is set for utilities, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies.

In accordance with the 2017 Rate Case Decision, APS filed its request for a RCP export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021. On April 29, 2022, APS filed an application to decrease the RCP price to 8.46 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2022. On July 12, 2022, the ACC approved the RCP as filed.

See "2016 Retail Rate Case Filing" above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

After various proceedings between September 2016 and March 2020, at which time Burns' appeal of a prior dismissal by the trial court was pending before the Arizona Court of Appeals, Burns' position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. On March 4, 2021, the Court of Appeals found Burns' motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day.

In its March 4, 2021, opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021, requesting that the petition be denied. The Arizona Supreme Court granted Burns' petition and heard oral argument on March 8, 2022. Pinnacle West and APS cannot predict the outcome of this matter.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and subsequent drafts were filed by ACC Staff in July 2019, February 2020, and July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. A new Energy Efficiency Standard ("EES") was not included in the proposed rules. These rules would have required utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, these rules would have changed the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. During March and April 2022, the ACC reviewed several proposed amendments for a proposed all-source RFP and IRP rulemaking package but delayed a vote on the amendments to a future date. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS's IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by 2030 and authorizing future rate base treatment of qualifying demand-side resources as proposed in future rate cases. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year PPAs with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

On July 16, 2020, FERC issued a final rule revising FERC's regulations implementing PURPA. The final rule went into effect on December 31, 2020.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur and customers will have four months to pay back their deposit and any remaining delinquent amounts. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method

disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method (June 1 – October 15) for disconnection moratoriums. On November 2, 2021, the ACC approved the final rules, and on November 23, 2021, the rules were submitted to the Arizona Office of the Attorney General for final review and approval. The new rules became effective on April 18, 2022, and APS has employed the calendar method for its disconnection moratorium.

In accordance with the ACC service disconnection rules, APS now suspends the disconnection of customers for nonpayment from June 1 through October 15 each year ("Annual Disconnection Moratorium"). Customers with past due balances of $75 or greater as of the beginning of the Annual Disconnection Moratorium are automatically placed on six-month payment arrangements. In addition, APS voluntarily began waiving late payment fees of its customers ("Late Fee Waivers") on March 13, 2020. APS is continuing to apply Late Fee Waivers for residential customers; however, effective May 1, 2022, late payment fees for commercial and industrial customers were reinstated. Since the suspensions and moratoriums on disconnections began, APS has experienced an increase in bad debt expense and the related write-offs of delinquent customer accounts.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. In April 2022, the Arizona Legislature passed a bill that would nullify a 24-year-old electric deregulation law that has been in place since 1998. The bill was signed by the Arizona Governor and will take effect September 23, 2022. APS cannot predict what impact, if any, this change will have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates of convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which has been returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. The ACC did not issue a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Rate Case filing with the ACC.

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance and the appeal is proceeding in the normal course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of June 30, 2022. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See above for further discussion on the 2019 Rate Case decision.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of the Cholla Power Plant ("Cholla") and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if the United States Environmental Protection Agency ("EPA") approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS has committed to end the use of coal at its remaining Cholla units by 2025.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $39.5 million as of June 30, 2022, in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allows for decommissioning activities to begin after the plant ceased operations. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset.

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant, $57.4 million as of June 30, 2022, in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset, $15.4 million as of June 30, 2022. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

7. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan, a non-qualified supplemental excess benefit retirement plan, and other postretirement benefit plans for the employees of Pinnacle West and our subsidiaries. The other postretirement benefit plans include a group life and medical plan and a post-65 retiree health reimbursement arrangement ("HRA"). Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets

is their fair value at the measurement date.

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants) (dollars in thousands):

	Pension Benefits				Other Benefits			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021	2022	2021	2022	2021
Service cost — benefits earned during the period	$ 13,406	$ 14,939	$ 27,737	$ 30,618	$ 4,017	$ 4,341	$ 8,235	$ 8,898
Non-service costs (credits):								
Interest cost on benefit obligation	26,723	24,614	53,746	49,283	4,283	4,095	8,746	8,257
Expected return on plan assets	(46,494)	(50,706)	(92,888)	(101,314)	(11,511)	(10,361)	(23,021)	(20,722)
Amortization of:								
Prior service credit	—	—	—	—	(9,447)	(9,427)	(18,894)	(18,854)
Net actuarial loss (gain)	3,989	3,989	8,757	7,974	(3,436)	(2,641)	(6,418)	(5,046)
Net periodic benefit	$ (2,376)	$ (7,164)	$ (2,648)	$ (13,439)	$ (16,094)	$ (13,993)	$ (31,352)	$ (27,467)
Portion of benefits charged to expense	$ (4,722)	$ (8,614)	$ (8,012)	$ (16,625)	$ (11,523)	$ (9,608)	$ (22,418)	$ (19,136)

Contributions

Pinnacle West has not made any voluntary contributions to our pension plan year-to-date in 2022. The minimum required contributions for the pension plan are zero and Pinnacle West does not expect to make any contributions in 2022, 2023 or 2024. With regard to contributions to Pinnacle West's other postretirement benefit plan, Pinnacle West has not made a contribution year-to-date in 2022 and does not expect to make any contributions in 2022, 2023 or 2024.

8. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. APS will retain the assets through 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2022 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

For regulatory reporting purposes, APS accounts for the three leases as operating leases for income statement and cash flow statement purposes, and for balance sheet purposes all three leases are classified as finance leases.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the Nuclear Regulatory Commission ("NRC") issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $315 million beginning in 2022, and up to $501 million over the lease terms.

9. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, emissions allowances, and interest rates. Risks associated with market volatility are managed by utilizing various physical and financial derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and natural gas. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are presented gross, which increases both revenues and fuel and purchased power costs in our Comparative Statements of Income, but does not impact our financial condition, net income or cash flows.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheets as an asset or liability and are measured at fair value. See Note 11 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate, see Note 6. Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

The following table shows the outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	Unit of Measure	June 30, 2022	December 31, 2021
Power	GWh	1,208	—
Gas	Billion cubic feet	168	155

Gains and Losses from Derivative Instruments

For the three and six months ended June 30, 2022 and 2021, APS had no derivative instruments in designated accounting hedging relationships.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments (dollars in thousands):

		Three Months Ended June 30,		Six Months Ended June 30,	
Commodity Contracts	Financial Statement Location	2022	2021	2022	2021
Net Gain Recognized in Income	Fuel and purchased power (a)	$ 62,525	$ 95,116	$ 286,267	$ 121,975

(a) Amounts are before the effect of PSA deferrals.

Derivative Instruments in the Comparative Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements and are reported gross on the Comparative Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting

tables presented below.

The following tables provide information about the fair value of our risk management activities reported on a gross basis and the impacts of offsetting relating to transactions executed under master netting arrangements. While certain amounts may be eligible for offsetting under master netting arrangements, for FERC reporting purposes we do not offset on the balance sheet. These amounts relate to commodity contracts and are located in the assets and liabilities from derivative instrument lines of our Comparative Balance Sheets.

		Eligible for Offsetting		
As of June 30, 2022: (dollars in thousands)	Gross Recognized Derivatives (a)	Derivatives	Cash Collateral/Other (b)	Net Derivatives After Impacts of Offsetting
Current assets	$ 177,765	$ (357)	$ —	$ 177,408
Investments and other assets	111,847	—	—	111,847
Total assets	289,612	(357)	—	289,255
Current liabilities	(4,053)	357	(40,430)	(44,126)
Total	$ 285,559	$ —	$ (40,430)	$ 245,129

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral received from counterparties of $40,430 that is subject to offsetting. We had total cash collateral received from counterparties of $1,900 and cash margin provided to counterparties of $50.

		Eligible for Offsetting		
As of December 31, 2021: (dollars in thousands)	Gross Recognized Derivatives (a)	Derivatives	Cash Collateral/Other (b)	Net Derivatives After Impacts of Offsetting
Current assets	$ 66,777	$ (3,346)	$ —	$ 63,431
Investments and other assets	48,302	(1,394)	—	46,908
Total assets	115,079	(4,740)	—	110,339
Current liabilities	(6,084)	3,346	—	(2,738)
Deferred credits and other	(1,394)	1,394	—	—
Total liabilities	(7,478)	4,740	—	(2,738)
Total	$ 107,601	$ —	$ —	$ 107,601

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting. We had total cash collateral received from counterparties of $1,635 and cash margin provided to counterparties of $50.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of June 30, 2022, we have one counterparty for which our exposure represents approximately 19% of $249 million of risk management assets. This exposure relates to a master agreement with the counterparty, and the counterparty is rated as investment grade. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these counterparties could default, resulting in a material impact on earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

The following table provides information about our derivative instruments that have credit-risk-related contingent features (dollars in thousands):

	June 30, 2022
Aggregate fair value of derivative instruments in a net liability position	$ 1,882
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	883

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

We have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could require us to post additional collateral of approximately $77 million if our debt credit ratings were to fall below investment grade.

10. Commitments and Contingencies

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007, through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2022.

APS has submitted seven claims pursuant to the terms of the August 18, 2014 settlement agreement, for seven separate time periods during July 1, 2011 through June 30, 2020. The DOE has approved and paid $111.8 million for these claims (APS's share is $32.5 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers. See Note 6. On November 1, 2021, APS filed its eighth claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). On March 22, 2022, the DOE approved a payment of $12.1 million (APS's share is $3.5 million) and on April 19, 2022, APS received this payment.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident of up to approximately $13.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of approximately $13.1 billion of liability coverage is provided through a mandatory industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $137.6 million, subject to a

maximum annual premium of approximately $20.5 million per incident. Based on APS's ownership interest in the three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $120.1 million, with a maximum annual retrospective premium of approximately $17.9 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $22.3 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $62.8 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

Contractual Obligations

As of June 30, 2022, our fuel and purchased power and purchase obligation commitments have increased from the information provided in our 2021 FERC Form 1. The increase is primarily due to new purchased power and energy storage commitments of approximately $1.2 billion. The majority of the changes relate to 2024 and thereafter. This amount includes approximately $500 million of commitments relating to a new purchased power lease contract that is included in our non-commenced lease discussion below.

At June 30, 2022, we have various lease arrangements that have been executed but have not yet commenced. These arrangements primarily relate to energy storage assets, with expected lease commencement dates ranging from September 2022 through June 2024, with terms expiring through May 2044. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $1.8 billion over the term of the arrangements. For additional information regarding our lease commitments see our 2021 FERC Form 1. Certain of these non-commenced lease agreements were previously expected to commence in June 2022; however, during the second quarter of 2022 due to delays impacting the leased asset's in-service date, the lease commencement date has been delayed from June 2022 to September 2022. APS is currently working with the lessor to determine if this revised lease commencement date will be achieved.

Other than the items described above, there have been no material changes, as of June 30, 2022, outside the normal course of business in contractual obligations from the information provided in our 2021 FERC Form 1. See Note 5 for discussion regarding changes in our short-term and long-term debt obligations.

Superfund and Other Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a "PRP"). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS later in 2022. APS's estimated costs related to this investigation and study are approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third- party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS's use, storage, and disposal of substances containing per-and polyfluoroalkyl ("PFAS") compounds at the Ocotillo power plant site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash ("SIBW") Superfund site. The SIBW Superfund site includes the APS Ocotillo power plant site. On April 29, 2022, APS filed its response to this information request. At the present time, we are unable to predict the outcome of this matter and expenditures related to this matter cannot be reasonably estimated.

Arizona Attorney General Matter

APS received civil investigative demands from the Attorney General seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which was returned to customers as restitution.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance and the appeal is proceeding in the normal course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of June 30, 2022. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 6 for additional information regarding the Four Corners SCR cost recovery.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on Four Corners. EPA required the plant to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plant. Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred.

In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See "Cholla" in Note 6 for information regarding future plans for Cholla and details related to the resulting regulatory asset and see "Four Corners SCR Cost Recovery" above regarding recovery of the Four Corners SCR project.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, including supporting the passage of new state legislation providing ADEQ with appropriate permitting authority for CCR under the state

without their own permit programs and on their lands. Although APS has taken steps to develop a CCR permitting program, including supporting the passage of new state legislation providing APS with appropriate permitting authority for CCR under the state solid waste management program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits. The proposal remains pending.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019, to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's July 29, 2020, final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure was submitted to EPA on November 30, 2020, and is currently pending. If granted, this application would allow the continued disposal of CCR within Cholla's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025. This application will be subject to public comment and, potentially, judicial review. EPA began taking action on these applications in January 2022, deeming APS's application for the Cholla facility "complete." We expect to have a proposed decision from EPA regarding Cholla in 2023.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations or cash flows.

EPA Climate Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. Thereafter, on June 30, 2022, the U.S. Supreme Court reversed the D.C. Circuit's ruling, holding that existing power plant carbon regulations on the scale of the CPP are not authorized by the federal Clean Air Act. While the Biden administration has nonetheless expressed an intent to continue its effort to regulate carbon emissions in this sector more aggressively under the Clean Air Act (consistent with the U.S. Supreme Court's June 30 ruling), we cannot at this time predict the outcome of pending EPA rulemaking proceedings related to the regulation of carbon emissions from existing power plants.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. The EAB denied the environmental group petition on September 30, 2020. While the environmental groups had filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit, on May 2, 2022, the parties to the litigation executed a settlement agreement. We do not anticipate that this agreement will have a material impact on our financial position, results of operations, or cash flows.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of June 30, 2022, standby letters of credit totaled $0.2 million and expire in 2023. As of June 30, 2022, surety bonds expiring through 2023 totaled $0.3 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

11. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 — Other significant observable inputs, including quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active, and model-derived valuations whose inputs are observable (such as yield curves).

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category may include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of Net Asset Value ("NAV") as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV as a practical expedient are included in our fair value disclosures; however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 9 in the 2021 FERC Form 1 for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3.

Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account and the active union employee medical account. See Note 12 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustees' and escrow agent's internal operating controls and valuation processes.

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These fixed income instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short-term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trusts' equity security investments are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

The nuclear decommissioning trusts and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid, investments are valued using active market prices.

Fair Value Tables

The following table presents the fair value at June 30, 2022 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 281,107	$ 8,505	$ —		$ 289,612
Nuclear decommissioning trust:						
Equity securities	12,773	—	—	1,401	(a)	14,174
U.S. commingled equity funds	—	—	—	460,619	(b)	460,619
U.S. Treasury debt	211,284	—	—	—		211,284
Corporate debt	—	177,297	—	—		177,297
Mortgage-backed securities	—	135,858	—	—		135,858
Municipal bonds	—	67,943	—	—		67,943
Other fixed income	—	8,913	—	—		8,913
Subtotal nuclear decommissioning trust	224,057	390,011	—	462,020		1,076,088
Other special use funds:						
Equity securities	29,093	—	—	938	(a)	30,031
U.S. Treasury debt	310,667	—	—	—		310,667
Municipal bonds	—	5,708	—	—		5,708
Subtotal other special use funds	339,760	5,708	—	938		346,406
Total assets	$ 563,817	$ 676,826	$ 8,505	$ 462,958		$ 1,712,106
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (94)	$ (3,959)	$ —		$ (4,053)

(a) Represents net pending securities sales and purchases.
(b) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

The following table presents the fair value at December 31, 2021 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 115,079	$ —	$ —		$ 115,079
Nuclear decommissioning trust:						
Equity securities	45,264	—	—	(27,782)	(a)	17,482
U.S. commingled equity funds	—	—	—	595,048	(b)	595,048
U.S. Treasury debt	240,745	—	—	—		240,745
Corporate debt	—	203,454	—	—		203,454
Mortgage-backed securities	—	155,574	—	—		155,574
Municipal bonds	—	72,189	—	—		72,189
Other fixed income	—	10,265	—	—		10,265
Subtotal nuclear decommissioning trust	286,009	441,482	—	567,266		1,294,757
Other special use funds:						
Equity securities	47,570	—	—	936	(a)	48,506
U.S. Treasury debt	298,170	—	—	—		298,170
Municipal bonds	—	11,734	—	—		11,734
Subtotal other special use funds	345,740	11,734	—	936		358,410
Total assets	$ 631,749	$ 568,295	$ —	$ 568,202		$ 1,768,246
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (4,740)	$ (2,738)	$ —		$ (7,478)

(a) Represents net pending securities sales and purchases.
(b) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote or other characteristics of the product. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment. See Note 6.

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.
Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

Financial Instruments Not Carried at Fair Value

The carrying value of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 5 for our long-term debt fair values.

12. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds

We have investments in debt and equity securities held in Nuclear Decommissioning Trusts, Coal Reclamation Escrow Account, and an Active Union Employee Medical Account. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments at their fair value on our Comparative Balance Sheets. See Note 11 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts — APS established external decommissioning trusts in accordance with NRC regulations to fund the future costs APS expects to incur to decommission Palo Verde. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities.

Coal Reclamation Escrow Account — APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because of the ability of APS to recover coal reclamation costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

Active Union Employee Medical Account — APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2021, APS was reimbursed $15 million for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	June 30, 2022				
	Fair Value				
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total	Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 473,392	$ 29,093	$ 502,485	$ 327,032	$ (183)

Available for sale-fixed income securities	601,295	316,375	917,670	(a)	2,997	(56,826)
Other	1,401	938	2,339	(b)	—	—
Total	$ 1,076,088	$ 346,406	$ 1,422,494		$ 330,029	$ (57,009)

(a) As of June 30, 2022, the amortized cost basis of these available-for-sale investments is $971 million.
(b) Represents net pending securities sales and purchases.

	December 31, 2021					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 640,312	$ 47,570	$ 687,882		$ 451,387	$ —
Available for sale-fixed income securities	682,227	309,904	992,131	(a)	24,283	(4,063)
Other	(27,782)	936	(26,846)	(b)	—	—
Total	$ 1,294,757	$ 358,410	$ 1,653,167		$ 475,670	$ (4,063)

(a) As of December 31, 2021, the amortized cost basis of these available-for-sale investments is $972 million.
(b) Represents net pending securities sales and purchases.

The following tables set forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities (dollars in thousands):

	Three Months Ended June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2022			
Realized gains	$ 6,282	$ —	$ 6,282
Realized losses	(12,439)	—	(12,439)
Proceeds from the sale of securities (a)	309,966	20,466	330,432
2021			
Realized gains	$ 1,406	$ —	$ 1,406
Realized losses	(1,146)	—	(1,146)
Proceeds from the sale of securities (a)	190,340	17,524	207,864

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

	Six Months Ended June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2022			
Realized gains	$ 7,305	$ —	$ 7,305
Realized losses	$ (19,674)	$ —	$ (19,674)
Proceeds from the sale of securities (a)	$ 629,659	$ 62,011	$ 691,670
2021			
Realized gains	$ 4,374	$ —	$ 4,374
Realized losses	(5,294)	—	(5,294)
Proceeds from the sale of securities (a)	425,068	162,774	587,842

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

Fixed Income Securities Contractual Maturities

The fair value of APS's fixed income securities, summarized by contractual maturities, at June 30, 2022, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 13,114	$ 47,528	$ 40,224	$ 100,866
1 year – 5 years	192,566	31,422	150,008	373,996
5 years – 10 years	127,287	—	43,023	170,310
Greater than 10 years	268,328	4,170	—	272,498
Total	$ 601,295	$ 83,120	$ 233,255	$ 917,670

13. Changes in Accumulated Other Comprehensive Loss

The following tables show the changes in APS's accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits

Three Months Ended June 30,			
Balance March 31, 2022	$	(34,060)	
OCI (loss) before reclassifications		(3,160)	
Amounts reclassified from accumulated other comprehensive loss		999	(a)
Balance June 30, 2022	$	(36,221)	
Balance March 31, 2021	$	(39,991)	
OCI (loss) before reclassifications		(914)	
Amounts reclassified from accumulated other comprehensive loss		1,073	(a)
Balance June 30, 2021	$	(39,832)	

		Pension and Other Postretirement Benefits	
Six Months Ended June 30,			
Balance December 31, 2021	$	(34,880)	
OCI (loss) before reclassifications		(3,160)	
Amounts reclassified from accumulated other comprehensive loss		1,819	(a)
Balance June 30, 2022	$	(36,221)	
Balance December 31, 2020	$	(40,918)	
OCI (loss) before reclassifications		(914)	
Amounts reclassified from accumulated other comprehensive loss		2,000	(a)
Balance June 30, 2021	$	(39,832)	

(a) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost (see Note 7).

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(40,918,418)		68	(40,918,350)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				1,999,970			1,999,970		
3	Preceding Quarter/Year to Date Changes in Fair Value				(913,761)			(913,761)		
4	Total (lines 2 and 3)				1,086,209			1,086,209	255,033,888	256,120,097
5	Balance of Account 219 at End of Preceding Quarter/Year				(39,832,209)		68	(39,832,141)		
6	Balance of Account 219 at Beginning of Current Year				(34,880,454)		68	(34,880,386)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				1,819,186			1,819,186		
8	Current Quarter/Year to Date Changes in Fair Value				(3,160,160)			(3,160,160)		
9	Total (lines 7 and 8)				(1,340,974)			(1,340,974)	194,167,847	192,826,873
10	Balance of Account 219 at End of Current Quarter/Year				(36,221,428)		68	(36,221,360)		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	21,642,319,662	21,642,319,662					
4	Property Under Capital Leases	1,059,381,213	1,059,381,213					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,300,929,096	1,300,929,096					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	24,002,629,971	24,002,629,971					
9	Leased to Others							
10	Held for Future Use	10,206,915	10,206,915					
11	Construction Work in Progress	1,270,141,591	1,270,141,591					
12	Acquisition Adjustments	255,525,921	255,525,921					
13	Total Utility Plant (8 thru 12)	25,538,504,398	25,538,504,398					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	8,525,604,547	8,525,604,547					
15	Net Utility Plant (13 less 14)	17,012,899,851	17,012,899,851					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	7,421,948,808	7,421,948,808					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	1,021,651,853	1,021,651,853					
22	Total in Service (18 thru 21)	8,443,600,661	8,443,600,661					
23	Leased to Others							
24	Depreciation							

25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	82,003,886	82,003,886					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	8,525,604,547	8,525,604,547					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

Electric Plant In Service and Accum Provision For Depr by Function

1. Report below the original cost of plant in service by function. In addition to Account 101, include Account 102, and Account 106. Report in column (b) the original cost of plant in service and in column(c) the accumulated provision for depreciation and amortization by function.

Line No.	Item (a)	Plant in Service Balance at End of Quarter (b)	Accumulated Depreciation And Amortization Balance at End of Quarter (c)
1	Intangible Plant	1,049,697,517	775,353,960
2	Steam Production Plant	2,294,173,200	1,114,963,692
3	Nuclear Production Plant	3,280,623,068	1,734,574,925
4	Hydraulic Production - Conventional		
5	Hydraulic Production - Pumped Storage		
6	Other Production	3,673,862,571	1,174,973,875
7	Transmission	3,549,915,747	1,045,300,588
8	Distribution	7,763,311,806	2,056,749,134
9	Regional Transmission and Market Operation		
10	General	1,331,664,849	541,684,487
11	TOTAL (Total of lines 1 through 10)	22,943,248,758	8,443,600,661

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
20	Total				
21	**Generation Studies**				
22	FACIL STDY,WA402826	2,313	143		143
23	FACIL STDY,WA425876	(588)	143		143
24	FACIL STDY,WA431805	(138)	143		143
25	FACIL STDY,WA431809	(140)	143		143
26	FACIL STDY,WA431939	(305)	143		143
27	FACIL STDY,WA432055	(681)	143		143
28	FACIL STDY,WA432060	409	143	190,343	143
29	FACIL STDY,WA444215	(1,519)	143		143
30	FACIL STDY,WA444217	(1,520)	143		143
31	FACIL STDY,WA459370	(794)	143		143
32	FACIL STDY,WA459429	(640)	143	6,500	143
33	FACIL STDY,WA459497	(840)	143		143
34	FACIL STDY,WA459895	10,037	143		143
35	FACIL STDY,WA459896	6,753	143		143
36	FACIL STDY,WA488493	4,709	143		143
37	FACIL STDY,WA517285	854	143		143
38	FACIL STDY,WA565967	41	143		143
39	FACIL STDY,WA602005	(68)	143		143
40	FACIL STDY,WA603220	(180)	143	30,000	143
41	FACIL STDY,WA511627	2,419	143		143
42	FACIL STDY,WA517253	4,020	143		143

43	FACIL STDY,WA545531	11,313	143		143
44	FACIL STDY,WA545728	8,434	143		143
45	FACIL STDY,WA546664	12,101	143		143
46	FACIL STDY,WA574357	10,839	143		143
47	INTERCSTDY,99-143-998	12,884,356	143		143
48	INTERCSTDY,WA546774	(174)	143	(5,954)	143
49	INTERCSTDY,WA611054	8,644	143		143
50	INTERCSTDY,WA617081	6,942	143	(5,000)	143
51	INTERCSTDY,WA669358	6,468	143		143
52	INTERCSTDY,WA676249		143	(5,000)	143
53	INTERCSTDY,WA684369		143	(5,000)	143
54	INTERCSTDY,WA600942		143	5,000	143
55	NA,02-3221A	(2,916)	143	4,377	143
56	NA,02-8111A	529	143	(820)	143
57	NA,02-8113A	3,443	143	(284)	143
58	NA,02-8201A	706	143	(706)	143
59	NA,02-8338A	838	143		143
60	NA,02-8340A	205	143		143
61	NA,02-8344A	(2,241)	143		143
62	NA,02-8350A	(70)	143		143
63	NA,02-8356A	2,966	143		143
64	NA,02-8364A	4,239	143		143
65	NA,ASU-SENSOR	968	143		143
66	NA,NFQ338-FAS	(2,928)	143	(55,000)	143
67	NA,Q230-MMA	(81)	143	(10,000)	143
68	NA,Q271-MMA	(81)	143	(10,000)	143
69	NA,Q442-LGIA	1,863	143		143
70	NA,Q443-LGIA	1,863	143		143
71	NA,Q444-LGIA	1,925	143		143
72	NA,Q445-LGIA	(3,785)	143	(500,000)	143
73	NA,Q446-LGIA	(3,460)	143	(500,000)	143
74	NA,Q447-LGIA	(604)	143	(250,000)	143
75	NA,Q448-LGIA	(3,433)	143	(500,000)	143
76	NA,Q449-LGIA	(3,419)	143	(500,000)	143

77	NA,Q450-LGIA	(3,606)	143	(500,000)	143
78	NA,Q451-LGIA	(2,646)	143	(500,000)	143
79	NA,Q452-LGIA	(2,922)	143	(500,000)	143
80	NA,Q453-LGIA	(3,743)	143	(500,000)	143
81	NA,Q454-LGIA	(3,164)	143	(500,000)	143
82	NA,Q455-LGIA	(3,646)	143	(500,000)	143
83	NA,Q456-LGIA	(482)	143	(160,000)	143
84	NA,Q457-LGIA	(3,234)	143	(500,000)	143
85	NA,Q458-LGIA	(1,158)	143	(250,000)	143
86	NA,Q459-LGIA	(2,909)	143	(500,000)	143
87	NA,Q460-LGIA	(2,909)	143	(500,000)	143
88	NA,Q461-LGIA	(1,661)	143	(320,000)	143
89	NA,Q462-LGIA	(3,552)	143	(500,000)	143
90	NA,Q463-LGIA	(108)	143	(250,000)	143
91	NA,Q464-LGIA	(1,621)	143	(250,000)	143
92	NA,Q465-LGIA	(3,074)	143	(500,000)	143
93	NA,Q466-LGIA	(3,606)	143	(500,000)	143
94	NA,Q467-LGIA	(1,546)	143	(250,000)	143
95	NA,Q468-LGIA	(2,997)	143	(500,000)	143
96	NA,Q469-LGIA	(3,136)	143	(500,000)	143
97	NA,Q470-LGIA	(1,211)	143	(250,000)	143
98	NA,Q471-LGIA	(1,489)	143	(250,000)	143
99	NA,Q472-LGIA	(2,955)	143	(500,000)	143
100	NA,Q473-LGIA	(2,556)	143	(500,000)	143
101	NA,Q474-LGIA	(3,566)	143	(500,000)	143
102	NA,Q475-LGIA	(1,541)	143	(250,000)	143
103	NA,SP104	461	143		143
104	NA,SP105	461	143		143
105	NA,WA683523	116	143		143
106	NA,WD-NEXTERA	2,399	143		143
107	SMG FACSTD,WA553147	10,063	143		143
108	SMG FACSTD,WA603213	(343)	143	30,000	143
109	SMG FACSTD,WA603214	(343)	143	30,000	143
110	SMG FACSTD,WA603216	(343)	143	30,000	143

111	SMG FACSTD,WA603217	(343)	143	30,000	143
112	SMG FACSTD,WA603223	(992)	143	30,000	143
113	SMG FACSTD,WA603224	(343)	143	30,000	143
114	SMG FACSTD,WA662456		143	(30,000)	143
115	SMG FACSTD,WA565767		143	3,900	143
116	SMG SISSTD,WA597916	8,121	143	33,670	143
117	SMG SISSTD,WA606497	84	143	22,275	143
118	SMG SISSTD,WA632339	2,289	143		143
119	SMG SISSTD,WA634317	9,503	143	33,930	143
120	SMG SISSTD,WA670141	3,528	143		143
121	SYSIMPTSTD,WA383670	5,446	143		143
122	SYSIMPTSTD,WA384886	(588)	143		143
123	SYSIMPTSTD,WA402547	697	143		143
124	SYSIMPTSTD,WA425874	2,777	143		143
125	SYSIMPTSTD,WA431719	(386)	143		143
126	SYSIMPTSTD,WA431807	(49)	143		143
127	SYSIMPTSTD,WA431944	(737)	143		143
128	SYSIMPTSTD,WA431968	(135)	143		143
129	SYSIMPTSTD,WA432059	6,514	143	18,720	143
130	SYSIMPTSTD,WA450463	(65)	143		143
131	SYSIMPTSTD,WA459432	2,618	143		143
132	SYSIMPTSTD,WA459505	(573)	143		143
133	SYSIMPTSTD,WA488489	(837)	143		143
134	SYSIMPTSTD,WA488579	(579)	143		143
135	SYSIMPTSTD,WA488582	(564)	143		143
136	SYSIMPTSTD,WA503830	(650)	143		143
137	SYSIMPTSTD,WA511477	(6)	143		143
138	SYSIMPTSTD,WA516333	(669)	143		143
139	SYSIMPTSTD,WA516518	(298)	143		143
140	SYSIMPTSTD,WA516741	1,721	143	5,590	143
141	SYSIMPTSTD,WA517446	473	143	5,590	143
142	SYSIMPTSTD,WA517447	689	143	5,590	143
143	SYSIMPTSTD,WA517448	99	143	5,590	143
144	SYSIMPTSTD,WA517449	(584)	143		143

145	SYSIMPTSTD,WA532273	(1)	143		143
146	SYSIMPTSTD,WA532276	(3)	143		143
147	SYSIMPTSTD,WA534568	5,381	143		143
148	SYSIMPTSTD,WA539190	(678)	143		143
149	SYSIMPTSTD,WA544770	1,085	143	1,560	143
150	SYSIMPTSTD,WA545423	193	143	1,560	143
151	SYSIMPTSTD,WA545425	(26)	143		143
152	SYSIMPTSTD,WA545722	(674)	143		143
153	SYSIMPTSTD,WA545757	(563)	143		143
154	SYSIMPTSTD,WA546276	(283)	143		143
155	SYSIMPTSTD,WA546547	(750)	143		143
156	SYSIMPTSTD,WA546548	(282)	143		143
157	SYSIMPTSTD,WA546667	(676)	143		143
158	SYSIMPTSTD,WA546767	(682)	143		143
159	SYSIMPTSTD,WA546770	(427)	143		143
160	SYSIMPTSTD,WA551476	1,664	143		143
161	SYSIMPTSTD,WA571836	(695)	143		143
162	SYSIMPTSTD,WA571837	(694)	143		143
163	SYSIMPTSTD,WA574418	(699)	143		143
164	SYSIMPTSTD,WA574485	(691)	143		143
165	SYSIMPTSTD,WA574522	(1,353)	143		143
166	SYSIMPTSTD,WA574523	(474)	143	2,243	143
167	SYSIMPTSTD,WA574525	2,505	143	78	143
168	SYSIMPTSTD,WA574690	(2)	143		143
169	SYSIMPTSTD,WA574721	(556)	143	1,820	143
170	SYSIMPTSTD,WA574749	(267)	143		143
171	SYSIMPTSTD,WA574775	2,181	143	78	143
172	SYSIMPTSTD,WA574782	3,413	143	78	143
173	SYSIMPTSTD,WA574816	(269)	143	2,080	143
174	SYSIMPTSTD,WA574818	495	143	2,243	143
175	SYSIMPTSTD,WA574838	2,589	143	78	143
176	SYSIMPTSTD,WA574842	(700)	143		143
177	SYSIMPTSTD,WA594256	(1,222)	143		143
178	SYSIMPTSTD,WA594257	(644)	143		143

179	SYSIMPTSTD,WA596156	(88)	143		143
180	SYSIMPTSTD,WA604606	210	143	3,575	143
181	SYSIMPTSTD,WA606554	(689)	143		143
182	SYSIMPTSTD,WA606616	(435)	143	3,575	143
183	SYSIMPTSTD,WA606634	3,835	143	2,243	143
184	SYSIMPTSTD,WA606635	(404)	143	2,243	143
185	SYSIMPTSTD,WA606636	(405)	143	2,243	143
186	SYSIMPTSTD,WA606637	(404)	143	2,243	143
187	SYSIMPTSTD,WA606835	(438)	143		143
188	SYSIMPTSTD,WA606863	(489)	143	3,575	143
189	SYSIMPTSTD,WA606864	(685)	143		143
190	SYSIMPTSTD,WA606865	5,091	143	78	143
191	SYSIMPTSTD,WA606866	6,410	143	16,380	143
192	SYSIMPTSTD,WA606867	3,368	143	78	143
193	SYSIMPTSTD,WA606868	(446)	143	2,243	143
194	SYSIMPTSTD,WA606869	(568)	143		143
195	SYSIMPTSTD,WA606871	(603)	143		143
196	SYSIMPTSTD,WA606872	343	143	132,215	143
197	SYSIMPTSTD,WA606891	(1,179)	143		143
198	SYSIMPTSTD,WA606892	(438)	143		143
199	SYSIMPTSTD,WA606894	2,125	143	163	143
200	SYSIMPTSTD,WA606909	(609)	143		143
201	SYSIMPTSTD,WA606911	(485)	143	3,575	143
202	SYSIMPTSTD,WA606912	2,602	143	82	143
203	SYSIMPTSTD,WA606914	(421)	143		143
204	SYSIMPTSTD,WA606915	(1,375)	143		143
205	SYSIMPTSTD,WA618021	(21)	143		143
206	SYSIMPTSTD,WA630428	29,165	143		143
207	SYSIMPTSTD,WA634246	(434)	143		143
208	SYSIMPTSTD,WA634254		143		143
209	SYSIMPTSTD,WA634257	(446)	143		143
210	SYSIMPTSTD,WA636515	(1,314)	143		143
211	SYSIMPTSTD,WA636518	(1,312)	143		143
212	SYSIMPTSTD,WA636520	(632)	143		143

213	SYSIMPTSTD,WA636581	(681)	143		143
214	SYSIMPTSTD,WA636699	(1,270)	143	2,860	143
215	SYSIMPTSTD,WA636707	(1,224)	143		143
216	SYSIMPTSTD,WA636708	(1,254)	143	1,300	143
217	SYSIMPTSTD,WA636711	(1,281)	143	1,300	143
218	SYSIMPTSTD,WA636716	(680)	143		143
219	SYSIMPTSTD,WA636722	(672)	143		143
220	SYSIMPTSTD,WA636731	(682)	143		143
221	SYSIMPTSTD,WA636732	354	143		143
222	SYSIMPTSTD,WA636749	(675)	143		143
223	SYSIMPTSTD,WA636750	(678)	143		143
224	SYSIMPTSTD,WA636751	(678)	143		143
225	SYSIMPTSTD,WA636755	(678)	143		143
226	SYSIMPTSTD,WA636759	6	143		143
227	SYSIMPTSTD,WA636760	(4)	143		143
228	SYSIMPTSTD,WA636761	(1,008)	143	780	143
229	SYSIMPTSTD,WA636830	(1,328)	143	1,300	143
230	SYSIMPTSTD,WA636842	(1,328)	143	1,300	143
231	SYSIMPTSTD,WA636844	(1,316)	143	1,300	143
232	SYSIMPTSTD,WA636863	2,750	143		143
233	SYSIMPTSTD,WA636864	2,750	143		143
234	SYSIMPTSTD,WA636865	(1,366)	143		143
235	SYSIMPTSTD,WA636872	(1,230)	143	1,300	143
236	SYSIMPTSTD,WA636873	(1,238)	143	1,300	143
237	SYSIMPTSTD,WA636874	(1,361)	143		143
238	SYSIMPTSTD,WA636883	(680)	143		143
239	SYSIMPTSTD,WA636904	(1,356)	143		143
240	SYSIMPTSTD,WA636920	(1,359)	143		143
241	SYSIMPTSTD,WA636929	(1,050)	143	1,300	143
242	SYSIMPTSTD,WA636934	(1,358)	143		143
243	SYSIMPTSTD,WA636935	(677)	143		143
244	SYSIMPTSTD,WA636938	(1,357)	143		143
245	SYSIMPTSTD,WA637059	(680)	143		143
246	SYSIMPTSTD,WA637061	(677)	143		143

247	SYSIMPTSTD,WA637064	(1,066)	143	1,300	143
248	SYSIMPTSTD,WA637065	(1,230)	143		143
249	SYSIMPTSTD,WA637066	(1,122)	143	1,300	143
250	SYSIMPTSTD,WA637067	(677)	143	1,040	143
251	SYSIMPTSTD,WA637068	(1,358)	143		143
252	SYSIMPTSTD,WA661111	1,388	143	21,040	143
253	SYSIMPTSTD,WA334709	17	143	2,080	143
254	SYSIMPTSTD,WA488486	(71)	143		143
255	SYSIMPTSTD,WA517323	(70)	143		143
39	Total	12,970,055		(12,329,560)	
40	Grand Total	12,970,055		(12,329,560)	

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred Compensation Amortize through 2036	35,355,238		131,174,224	1,104,119	34,251,119
2	Capital Contribution on Phoenix-Mead Transmission U-1345-90-269 Amortize through 2050	9,297,145		108	83,010	9,214,135
3	Income Taxes - AFUDC Equity E-01345A-03-0437 Amortize through 2052	172,696,393	5,279,817	283,410.1	2,706,827	175,269,383
4	Deferred Fuel and Purchased Power E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2023	354,816,088	92,597,104	411.8,555,547,502,411.9	57,399,920	390,013,272
5	Deferred Fuel and Purchased Power - Interest E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2023	271,683	557,714			829,397
6	Navajo Coal Reclamation E-01345A-08-0172 Amortize through 2026	16,096,134		501	745,655	15,350,479
7	Pension and Other Postretirement Benefits E-01345A-08-0172	506,280,338	10,474,936	128, 228.3, 926	2,425,412	514,329,862
8	Income Taxes - Change in Rates Amortize through 2051	(122,926)	13,643			(109,283)
9	Income Taxes - Medicare Subsidy Amortize through 2024	3,640,960		283,410.1	438,279	3,202,681
10	Income Taxes - Investment Tax Credit Basis Adjustment E-01345A-16-0036 Amortize through 2056	24,725,641		283,410.1	293,343	24,432,298
11	Property Tax Deferral E-01345A-11-0224 Amortize thorugh 2027	47,484,122		408	2,142,342	45,341,780
12	Lost Fixed Cost Recovery E-01345A-11-0224 Amortize through 2023	57,808,334		440,442	14,020,276	43,788,058
13	Retired Power Plant Costs Amortize through 2033	110,357,486		403, 404, 407	4,087,099	106,270,387
14	Four Corners Cost Deferral Amortize through 2024	22,055,956		407	2,019,145	20,036,811
15	SCR Deferral E-01345A-16-0036 Amortize though 2031	103,734,493		407	2,036,739	101,697,754
16	TCA Balancing account E-01345A-16-0036 Amortize through 2023	10,242,180	1,175,052	400	2,612,660	8,804,572
17	Deficient Deferred Income Taxes Tax Cuts & Jobs Act-ACC Portion to be amortized through 2046	2,766,390		283/410.1	(a)40,167	2,726,223
18	Deficient Deferred Income Taxes Tax Cuts & Jobs Act-FERC Amortize through 2058	8,500,801		283/410.1	(b)189,207	8,311,594

19	Tax Expense Adjustor Mechanism Amortize through 2031	6,337,009		400	163,889	6,173,120
20	Ocotillo Deferral E-01345A-16-0036 Amortize though 2031	145,273,625		407	2,376,814	142,896,811
21	Demand Side Management Amortize through 2023		983,117			983,117
22	Customer bill relief deferral E-00000A-19-128	1,800,000				1,800,000
23	Active Union Medical Trust E-01345A-19-0236	10,452,631	3,251,262			13,703,893
24	E3/E4 CC Fees Deferral E-01345A-19-0236	104,161	98,398			202,559
44	TOTAL	1,649,973,882	114,431,043		94,884,903	1,669,520,022

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

FOOTNOTE DATA

(a) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Deficient Deferred Income Taxes – Tax Cuts and Jobs Act-ACC: Amount Amortized to Income Tax Expense Account 410.1: $30,238

(b) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Deficient Deferred Income Taxes – Tax Cuts and Jobs Act-FERC: Amount Amortized to Income Tax Expense Account 410.1: $142,436

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Asset Retirement Obligations FERC Order# 552 Amortize through 2057	537,719,981	108,126,230,403	161,144,486		376,575,495
2	Spent Nuclear Fuel Storage E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2027	43,767,599	518	1,810,588		41,957,011
3	Income Taxes - Unamortized Investment Tax Credit E-01345A-05-0816, -0826, -0827 Amortize through 2056	49,516,440	190	589,811		48,926,629
4	Sundance Maintenance E-01345A-05-0816, -0826, -0827 Amortize through 2031	14,571,079			774,045	15,345,124
5	Income Tax - Change in Rates Amortize through 2047	67,408,762	190/410.1	1,005,854		66,402,908
6	Renewable Energy Standard E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2024	31,180,599	549	25,513,499	20,225,850	25,892,950
7	Demand Side Management E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2023	10,326,945	908	15,764,347	14,651,409	9,214,007
8	Other Postretirement Benefits E-01345A-08-0172	362,485,280	926.1	12,779,562	5,963,315	355,669,033
9	Removal costs Cholla	15,431,117			233,038	15,664,155
10	Removal costs Saguaro	11,416,112			77,437	11,493,549
11	Property Tax Deferral E01345A-11-0224 Amortize though 2024	19,024,375	4081	1,167,768		17,856,607
12	Four Corners Coal Reclamation E-013454A-05-0816, -0826, -0827 Amortize through 2038	53,944,488	501	1,348,221	578,919	53,175,186
13	Deferred Gain on Sale of Property E-01345A-09-0357 Amortize through 2023	1,296,764	421.1	605,696	743	691,811
14	Excess Deferred Income Taxes Tax Cuts & Jobs Act-ACC Portion to be amortized through 2046	1,013,129,113	190/411.1	(a) 14,560,323		998,568,790
15	Excess Deferred Income Taxes Tax Cuts & Jobs Act-FERC Amortize through 2058	237,247,921	190/411.1	(b) 2,758,870		234,489,051
16	Tax Expense Adjustor Mechanism E-01345A-18-0003	4,835,048				4,835,048
17	EIS Balancing Account Amortize through 2024	664,177	400	15,401	483,261	1,132,037
18	FERC Transmission True up Amortize through 2024	27,969,881	400	3,942,197	8,830,416	32,858,100
19	Deferred Fuel and Purchased Power - Mark-to-Market E-01345A-03-0437, E-01345A-05-0816, -0826, -0827 Amortize through 2024	306,091,946	547,555	20,533,092		285,558,854

20	TCA Balancing Account Amortize through 2024				964,199	964,199
41	TOTAL	2,808,027,627		263,539,715	52,782,632	2,597,270,544

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

FOOTNOTE DATA

(a) Concept: DecreaseInOtherRegulatoryLiabilities

Excess Deferred Income Taxes - Tax Cuts & Jobs Act-ACC: Amount Amortized to Income Tax Expense Account 411.1: $10,961,012

(b) Concept: DecreaseInOtherRegulatoryLiabilities

Excess Deferred Income Taxes - Tax Cuts & Jobs Act-FERC: Amount Amortized to Income Tax Expense Account 411.1: $2,076,877

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	904,934,699	1,913,324,211	6,435,148	14,223,711	1,197,432	1,177,343
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	[a]721,374,172	[a]1,390,441,902	6,255,786	12,729,685	136,629	135,503
5	Large (or Ind.) (See Instr. 4)	[b]90,345,156	[b]176,211,405	1,023,332	2,165,830	2,867	3,019
6	(444) Public Street and Highway Lighting	10,394,781	20,153,935	53,281	107,124	1,311	1,266
7	(445) Other Sales to Public Authorities	71,203	132,468	885	1,886	138	135
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,727,120,011	3,500,263,921	13,768,432	29,228,236	1,338,377	1,317,266
11	(447) Sales for Resale	71,418,609	214,111,295	1,229,795	3,850,839	54	45
12	TOTAL Sales of Electricity	1,798,538,620	3,714,375,216	14,998,227	33,079,075	1,338,431	1,317,311
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	1,798,538,620	3,714,375,216	14,998,227	33,079,075	1,338,431	1,317,311
15	Other Operating Revenues						
16	(450) Forfeited Discounts	155,616	3,648				
17	(451) Miscellaneous Service Revenues	[a](642,237)	[a]3,048,654				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	453,704	1,430,408				

20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	(a) 1,238,842	(b) 5,638,786				
22	(456.1) Revenues from Transmission of Electricity of Others	54,911,614	99,405,830				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	56,117,539	109,527,326				
27	TOTAL Electric Operating Revenues	1,854,656,159	3,823,902,542				

Line12, column (b) includes $ (a) 97,826,568 of unbilled revenues.
Line12, column (d) includes (a) 638,794 MWH relating to unbilled revenues

FERC FORM NO. 1/3-Q (REV. 12-05)

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Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

(c) Concept: MiscellaneousServiceRevenues

Sturgeon Project Temp Power		(443,798)
Other		(198,439)
Total	$	(642,237)

(d) Concept: OtherElectricRevenue

(456) - PCS Project	$	1,086,286
(456) - Management/Administration Fees		490,900
(456) - Fuel Loading		500,134
(456) - Other		162,356
(456) - Facility Charges		91,044
(456) - Participant Station Power Revenue		77,258
(456) - Surepay and Autopay Discount		(1,169,136)
Total	$	1,238,842

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

(g) Concept: MiscellaneousServiceRevenues

Connection Charges	$	2,692,992
TSMC Project Temp Power		248,066
Other		107,596
Total	$	3,048,654

(h) Concept: OtherElectricRevenue

(456) - PCS Project	$	2,987,068
(456) - Management/Administration Fees		1,537,208
(456) - Fuel Loading		1,280,656
(456) - Bid Fee Proceeds		1,190,000
(456) - Facility Charges		462,257
(456) - Other		165,027
(456) - Participant Station Power		153,705
(456) - Call Center Referrals		99,250
(456) - Surepay and Autopay Discount		(2,236,385)
Total	$	5,638,786

(i) Concept: RevenueFromSalesOfElectricityUnbilled

Unbilled Revenue		
1440-100 Residential	$	68,345,936
1442-100 Commercial		27,904,083
1442-102 Industrial		2,149,051
1442-104 Irrigation		16,408
1440-100 Hwy lighting		(244)
	$	98,415,234

(j) Concept: MegawattHoursOfElectricitySoldUnbilled

Unbilled Revenue	
1440-100 Residential	514,765
1442-100 Commercial	184,325
1442-102 Industrial	12,665
1442-104 Irrigation	218
1440-100 Hwy lighting	(3)
	711,970

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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46	TOTAL				

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional market, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
1	1. POWER PRODUCTION AND OTHER SUPPLY EXPENSES	
2	Steam Power Generation - Operation (500-509)	157,248,276
3	Steam Power Generation – Maintenance (510-515)	26,103,504
4	Total Power Production Expenses - Steam Power	183,351,780
5	Nuclear Power Generation – Operation (517-525)	82,049,968
6	Nuclear Power Generation – Maintenance (528-532)	19,166,907
7	Total Power Production Expenses - Nuclear Power	101,216,875
8	Hydraulic Power Generation – Operation (535-540.1)	
9	Hydraulic Power Generation – Maintenance (541-545.1)	
10	Total Power Production Expenses - Hydraulic Power	
11	Other Power Generation – Operation (546-550.1)	202,394,703
12	Other Power Generation – Maintenance (551-554.1)	22,521,175
13	Total Power Production Expenses - Other Power	224,915,878
14	Other Power Supply Expenses	
15	(555) Purchased Power	280,338,724
15.1	(555.1) Power Purchased for Storage Operations	
16	(556) System Control and Load Dispatching	(1,765,915)
17	(557) Other Expenses	1,652,884
18	Total Other Power Supply Expenses (line 15-17)	280,225,693
19	Total Power Production Expenses (Total of lines 4, 7, 10, 13 and 18)	789,710,226
20	2. TRANSMISSION EXPENSES	
21	Transmission Operation Expenses	
22	(560) Operation Supervision and Engineering	653,113
24	(561.1) Load Dispatch-Reliability	1,825,911
25	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,811,979
26	(561.3) Load Dispatch-Transmission Service and Scheduling	454,884

27	(561.4) Scheduling, System Control and Dispatch Services	1,354,465
28	(561.5) Reliability, Planning and Standards Development	1,135,855
29	(561.6) Transmission Service Studies	
30	(561.7) Generation Interconnection Studies	44,970
31	(561.8) Reliability, Planning and Standards Development Services	436,736
32	(562) Station Expenses	417,249
32.1	(562.1) Operation of Energy Storage Equipment	
33	(563) Overhead Lines Expenses	1,279,332
34	(564) Underground Lines Expenses	53,760
35	(565) Transmission of Electricity by Others	17,555,847
36	(566) Miscellaneous Transmission Expenses	5,925,234
37	(567) Rents	4,170,381
38	(567.1) Operation Supplies and Expenses (Non-Major)	
39	TOTAL Transmission Operation Expenses (Lines 22 - 38)	37,119,716
40	Transmission Maintenance Expenses	
41	(568) Maintenance Supervision and Engineering	338,785
42	(569) Maintenance of Structures	535,438
43	(569.1) Maintenance of Computer Hardware	
44	(569.2) Maintenance of Computer Software	
45	(569.3) Maintenance of Communication Equipment	116,343
46	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	
47	(570) Maintenance of Station Equipment	5,337,022
47.1	(570.1) Maintenance of Energy Storage Equipment	
48	(571) Maintenance of Overhead Lines	2,028,201
49	(572) Maintenance of Underground Lines	49,874
50	(573) Maintenance of Miscellaneous Transmission Plant	
51	(574) Maintenance of Transmission Plant	
52	TOTAL Transmission Maintenance Expenses (Lines 41 – 51)	8,405,663
53	Total Transmission Expenses (Lines 39 and 52)	45,525,379
54	3. REGIONAL MARKET EXPENSES	
55	Regional Market Operation Expenses	
56	(575.1) Operation Supervision	
57	(575.2) Day-Ahead and Real-Time Market Facilitation	788,927

58	(575.3) Transmission Rights Market Facilitation	
59	(575.4) Capacity Market Facilitation	
60	(575.5) Ancillary Services Market Facilitation	
61	(575.6) Market Monitoring and Compliance	
62	(575.7) Market Facilitation, Monitoring and Compliance Services	
63	Regional Market Operation Expenses (Lines 55 - 62)	788,927
64	Regional Market Maintenance Expenses	
65	(576.1) Maintenance of Structures and Improvements	
66	(576.2) Maintenance of Computer Hardware	
67	(576.3) Maintenance of Computer Software	
68	(576.4) Maintenance of Communication Equipment	
69	(576.5) Maintenance of Miscellaneous Market Operation Plant	
70	Regional Market Maintenance Expenses (Lines 65-69)	
71	TOTAL Regional Control and Market Operation Expenses (Lines 63,70)	788,927
72	4. DISTRIBUTION EXPENSES	
73	Distribution Operation Expenses (580-589)	32,970,827
74	Distribution Maintenance Expenses (590-598)	17,424,204
75	Total Distribution Expenses (Lines 73 and 74)	50,395,031

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

Electric Customer Accts, Service, Sales, Admin and General Expenses

Report the amount of expenses for customer accounts, service, sales, and administrative and general expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)
-	Operation	
1	(901-905) Customer Accounts Expenses	33,035,937
2	(907-910) Customer Service and Information Expenses	29,089,753
3	(911-917) Sales Expenses	6,831,817
4	8. ADMINISTRATIVE AND GENERAL EXPENSES	
5	Operation	
6	(920) Administrative and General Salaries	48,209,022
7	(921) Office Supplies and Expenses	4,094,716
8	(Less) (922) Administrative Expenses Transferred-Credit	15,400,000
9	(923) Outside Services Employed	25,273,021
10	(924) Property Insurance	662,909
11	(925) Injuries and Damages	6,387,499
12	(926) Employee Pensions and Benefits	(1,093,262)
13	(927) Franchise Requirements	
14	(928) Regulatory Commission Expenses	10,512,563
15	(929) (Less) Duplicate Charges-Cr.	
16	(930.1) General Advertising Expenses	4,456,388
17	(930.2) Miscellaneous General Expenses	(15,230,318)
18	(931) Rents	3,183,716
19	TOTAL Operation (Total of lines 6 thru 18)	71,056,254
20	Maintenance	
21	(935) Maintenance of General Plant	6,854,788
22	TOTAL Administrative and General Expenses (Total of lines 19 and 21)	77,911,042

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Arizona Public Service Company	Arizona Public Service Company	Arizona Public Service Company	FNS	OATT	Various	Various	[z][aa]0	6,694,818	6,694,818				
2	Arizona Public Service Company	Arizona Public Service Company	Arizona Public Service Company	FNS	OATT	Various	Various	[x]0	0	0			(59,637,974)	(59,637,974)
3	Arizona Public Service Company	Arizona Public Service Company	Arizona Public Service Company	FNS	OATT	Various	Various	[y]0	0	0			59,637,974	59,637,974
4	Ajo Improvement Company	Not Available	Not Available	[e] FNO	OATT	Various	Various	3	2,444	2,444	23,787	977	[ah](57)	24,707
5	City of Williams	Not Available	Not Available	[b] FNO	OATT	Various	Various	8	12,733	12,733	76,775	3,314	[ai]16,015	96,104
6	Navajo Tribal Utility Authority	Tucson Electric Power	Navajo Tribal Utility Authority	[c] FNO	OATT	Various	Various	8	8,591	8,591	81,289	1,526	[a]12,890	95,705
7	Navopache Electric Cooperative, Inc.	Not Available	Not Available	[d] FNO	OATT	Various	Various	59	8,895	8,895	551,112		[aj](2,929)	548,183
8	Southwest Public Power Agency	Not Available	Not Available	[g] FNO	OATT	Various	Various	149	263,595	263,595	1,416,156	81,637	[ak]1,680,332	3,178,125
9	TOUA	Not Available	Not Available	[f] FNO	OATT	Various	Various	14	14,717	14,717	126,172	4,773	[am]1,316	132,261
10	Broadview Energy JN LLC	Not Available	Not Available	[q] LFP	OATT	Various	Various	167	191,673	191,673	1,541,223		[an]5	1,541,228

11	Broadview Energy KW-LLC	Not Available	Not Available	[h] LFP	OATT	Various	Various	130	149,088	149,088	1,199,761		[ao](189)	1,199,572
12	Clines Corners Wind Farm LLC	Not Available	Not Available	[i] LFP	OATT	Various	Various	120	144,589	144,589	1,108,043		[ap]479	1,108,522
13	Duran Mesa Wind LLC	Not Available	Not Available	[j] LFP	OATT	Various	Various	51	72,999	72,999	470,791		[aq](275)	470,516
14	El Cabo Wind	Not Available	Not Available	[k] LFP	OATT	Various	Various	300	297,767	297,767	2,768,637		[ar](6,959)	2,761,678
15	Electrical District 3	Not Available	Not Available	[l] LFP	OATT	Various	Various	90	70,125	70,125	830,704		[as](1,536)	829,168
16	Grady Wind Energy Center- LLC	Not Available	Not Available	[m] LFP	OATT	Various	Various	200	227,786	227,786	1,845,779			1,845,779
17	NOVO BioPower LLC	Not Available	Not Available	[n] LFP	OATT	Various	Various	14	27,623	27,623	129,221		[at](700)	128,521
18	Public Service Company of New Mexico	Not Available	Not Available	[o] LFP	OATT	Various	Various	145	61,922	61,922	1,338,175		[au](1,680)	1,336,495
19	Salt River Project	Not Available	Not Available	[p] LFP	OATT	Various	Various	127	47,457	47,457	1,172,056			1,172,056
20	Southwest BioGas	Not Available	Not Available	[q] LFP	OATT	Various	Various	1	2,193	2,193	9,229	271	[av]4,262	13,762
21	Tecolote Wind LLC	Not Available	Not Available	[r] LFP	OATT	Various	Various	132	173,803	173,803	1,218,272		[aw]239	1,218,511
22	Trico Electric Cooperative Inc.	Not Available	Not Available	[s] LFP	OATT	Various	Various	2	4,171	4,171	18,458		[ax](116)	18,342
23	Tucson Electric Power Company	Not Available	Not Available	[t] LFP	OATT	Various	Various	110	39,169	39,169	1,015,304			1,015,304
24	Brookfield Renewable Trading and Marketing LP	Not Available	Not Available	SFP	OATT	Various	Various	0	52,327	52,327	261,518			261,518
25	Imperial Irrigation District Marketing	Not Available	Not Available	SFP	OATT	Various	Various	0	1,200	1,200	153,834			153,834
26	Macquarie Energy LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	39,818	39,818	461,502		[ay](50)	461,452
27	Red Cloud Wind Farm	Not Available	Not Available	SFP	OATT	Various	Various	0	134,751	134,751	1,273,908		[az]12,154	1,286,062
28	Clines Corners Wind Farm LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	57	57	966			966
29	Duran Mesa Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	186	186	2,897			2,897
30	EDF Trading North America, LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	1,576	1,576	8,449		[ba](24)	8,425
31	Guzman Power Markets LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	9,938	9,938	59,120			59,120
32	Guzman Renewable Energy Partners	Not Available	Not Available	SFP	OATT	Various	Various	0	1,696	1,696	9,053			9,053
33	Macquarie Energy LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	1,440	1,440	10,864		[bb](51)	10,813
34	Morgan Stanley	Not Available	Not Available	SFP	OATT	Various	Various	0	7,200	7,200	36,213			36,213
35	PacifiCorp	Not Available	Not Available	SFP	OATT	Various	Various	0	117,433	117,433	787,830			787,830
36		Not Available	Not Available	SFP	OATT	Various	Various	0	400	400	3,018			3,018

	Rainbow Energy Marketing													
37	Red Cloud Wind Farm	Not Available	Not Available	SFP	OATT	Various	Various	0	0	0	23,297			23,297
38	Salt River Project	Not Available	Not Available	SFP	OATT	Various	Various	0	21,051	21,051	229,393			229,393
39	Tecolote Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	797	797	11,226			11,226
40	Tenaska Power Services Co.	Not Available	Not Available	SFP	OATT	Various	Various	0	27,317	27,317	156,742			156,742
41	TransAlta Energy Marketing U.S. Inc.	Not Available	Not Available	SFP	OATT	Various	Various	0	130	130	2,897			2,897
42	Tucson Electric Power Company	Not Available	Not Available	SFP	OATT	Various	Various	0	5,648.00	5,648.00	38,862			38,862
43	UNIPER GLOBAL COMMODITIES NORTH AMERICA LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	9,945	9,945	50,818		[bc](159)	50,659
44	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	SFP	OATT	Various	Various	0	82	82	2,426		[bd](13)	2,413
45	Arizona Public Service Company	Not Available	Not Available	SFP	OATT	Various	Various	0	139	139	1,048			1,048
46	Avangrid Renewables, LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	75	75	565			565
47	Avista Corporation	Not Available	Not Available	SFP	OATT	Various	Various	0	102	102	2,638			2,638
48	Broadview Energy JN LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	1,216	1,216	[z](4,167)		[be]479	(3,688)
49	Broadview Energy KW-LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	2,800	2,800	11,424			11,424
50	Brookfield Renewable Trading and Marketing LP	Not Available	Not Available	SFP	OATT	Various	Various	0	3,468	3,468	26,104		[bf](149)	25,955
51	Clines Corners Wind Farm LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	6,289	6,289	83,444		[bg]254,610	338,054
52	CP Energy Marketing	Not Available	Not Available	SFP	OATT	Various	Various	0	600	600	5,054			5,054
53	DTE Energy Trading Inc	Not Available	Not Available	SFP	OATT	Various	Various	0	0	0	32,261		[bh](2)	32,259
54	Duran Mesa Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	8,546	8,546	114,410		[bi]114,123	228,533
55	Dynasty Power Inc	Not Available	Not Available	SFP	OATT	Various	Various	0	8,717	8,717	56,698			56,698
56	EDF Trading North America, LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	1,797	1,797	11,493			11,493
57	El Paso Electric Company	Not Available	Not Available	SFP	OATT	Various	Various	0	8	8	60			60
58	Grady Wind Energy Center- LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	3,960	3,960	[aa](36,926)		[bj]1,840	(35,086)
59	Guzman Power Markets LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	9,986	9,986	70,813			70,813
60	Imperial Irrigation District Marketing	Not Available	Not Available	SFP	OATT	Various	Various	0	217	217	2,522		[bk](1)	2,521

61	Los Angeles Wholesale Marketing	Not Available	Not Available	SFP	OATT	Various	Various	0	759	759	8,236		[bl](3)	8,233
62	Macquarie Energy LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	670	670	8,684			8,684
63	Mercuria Energy America LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	2,185	2,185	10,834		[bm](128)	10,706
64	Morgan Stanley	Not Available	Not Available	SFP	OATT	Various	Various	0	382	382	1,685			1,685
65	PacifiCorp	Not Available	Not Available	SFP	OATT	Various	Various	0	55,274	55,274	351,903		[bn](128)	351,775
66	Powerex	Not Available	Not Available	SFP	OATT	Various	Various	0	2,891	2,891	16,392			16,392
67	Public Service Company of New Mexico	Not Available	Not Available	SFP	OATT	Various	Various	0	3,020	3,020	18,442		[bo](99)	18,343
68	Rainbow Energy Marketing	Not Available	Not Available	SFP	OATT	Various	Various	0	12,231	12,231	102,786			102,786
69	Red Cloud Wind Farm	Not Available	Not Available	SFP	OATT	Various	Various	0	2,663	2,663	[ab](4,323)			(4,323)
70	Salt River Project	Not Available	Not Available	SFP	OATT	Various	Various	0	35,913	35,913	302,733			302,733
71	Shell Energy North America LP	Not Available	Not Available	SFP	OATT	Various	Various	0	4,892	4,892	33,945			33,945
72	Tecolote Wind LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	17,296	17,296	288,065		[bp]1,437	289,502
73	Tenaska Power Services Co.	Not Available	Not Available	SFP	OATT	Various	Various	0	40,739	40,739	332,198			332,198
74	The Energy Authority Inc.	Not Available	Not Available	SFP	OATT	Various	Various	0	562	562	8,049		[bq](1)	8,048
75	TransAlta Energy Marketing U.S. Inc.	Not Available	Not Available	SFP	OATT	Various	Various	0	4,779	4,779	39,883			39,883
76	Tri-State Generation and Transmission Assoc, Inc.	Not Available	Not Available	SFP	OATT	Various	Various	0	0	0	198			198
77	Tucson Electric Power Company	Not Available	Not Available	SFP	OATT	Various	Various	0	9,351	9,351	79,551			79,551
78	UNIPER GLOBAL COMMODITIES NORTH AMERICA LLC	Not Available	Not Available	SFP	OATT	Various	Various	0	6,855	6,855	46,346			46,346
79	Western Area Power Administration (DSW)	Not Available	Not Available	SFP	OATT	Various	Various	0	0	0			[br](3)	(3)
80	Salt River Project	Not Available	Not Available	NF	OATT	Various	Various	0	1,624	1,624	14,847		[bs]471	15,318
81	Arizona Public Service Company	Not Available	Not Available	NF	OATT	Various	Various	0	303	303	18		[bt]36,144	36,162
82	Avangrid Renewables, LLC	Not Available	Not Available	NF	OATT	Various	Various	0	1,378	1,378	7,307		[bu](3)	7,304
83	Black Hills Colorado Electric	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
84	Black Hills Power Inc	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
85	Broadview Energy JN LLC	Not Available	Not Available	NF	OATT	Various	Various	0	3,727	3,727	36,598		[bv]19,987	56,585

86	Broadview Energy KW-LLC	Not Available	Not Available	NF	OATT	Various	Various	0	4,003	4,003	29,901		[bw]3,234	33,135
87	Brookfield Renewable Trading and Marketing LP	Not Available	Not Available	NF	OATT	Various	Various	0	72	72	483		[bx](899)	(416)
88	ConocoPhillips- Inc.	Not Available	Not Available	NF	OATT	Various	Various	0	25	25	286		[by](4)	282
89	CP Energy Marketing	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
90	DTE Energy Trading Inc	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
91	Dynasty Power Inc	Not Available	Not Available	NF	OATT	Various	Various	0	3,686	3,686	23,006		[bz](115)	22,891
92	EDF Trading North America, LLC	Not Available	Not Available	NF	OATT	Various	Various	0	5	5	38		[ca](109)	(71)
93	El Paso Electric Company	Not Available	Not Available	NF	OATT	Various	Various	0	45	45	178		[cb]2,155	2,333
94	Exelon Generation Company, LLC	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
95	Guzman Power Markets LLC	Not Available	Not Available	NF	OATT	Various	Various	0	9,441	9,441	62,489		[cc](543)	61,946
96	Guzman Renewable Energy Partners	Not Available	Not Available	NF	OATT	Various	Various	0	1,171	1,171	7,901		[cd](59)	7,842
97	Imperial Irrigation District Marketing	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
98	Macquarie Energy LLC	Not Available	Not Available	NF	OATT	Various	Various	0	250	250	1,885		[ce](317)	1,568
99	Mag Energy Solutions, Inc	Not Available	Not Available	NF	OATT	Various	Various	0	345	345	2,718		[cf](22)	2,696
100	Mercuria Energy America LLC	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
101	Morgan Stanley	Not Available	Not Available	NF	OATT	Various	Various	0	534	534	4,579		[cg](490)	4,089
102	Nevada Power Company	Not Available	Not Available	NF	OATT	Various	Various	0	0	0			[ch]1	1
103	PacifiCorp	Not Available	Not Available	NF	OATT	Various	Various	0	4,200	4,200	24,318		[ci](438)	23,880
104	Powerex	Not Available	Not Available	NF	OATT	Various	Various	0	1,871	1,871	11,380		[cj](110)	11,270
105	Public Service Company of Colorado	Not Available	Not Available	NF	OATT	Various	Various	0	235	235	1,771			1,771
106	Rainbow Energy Marketing	Not Available	Not Available	NF	OATT	Various	Various	0	4,405	4,405	27,247		[ck](113)	27,134
107	Salt River Project	Not Available	Not Available	NF	OATT	Various	Various	0	1,358	1,358	10,457		[cl](187)	10,270
108	Shell Energy North America LP	Not Available	Not Available	NF	OATT	Various	Various	0	1,148	1,148	8,397		[cm](166)	8,231
109	Southern California Edison Company	Not Available	Not Available	NF	OATT	Various	Various	0	0	0			[cn](2)	(2)
110	TEC Energy	Not Available	Not Available	NF	OATT	Various	Various	0	0	0				
111	Tecolote Wind LLC	Not Available	Not Available	NF	OATT	Various	Various	0	686	686	4,246		[co]3,057	7,303

112	Tenaska Power Services Co.	Not Available	Not Available	NF	OATT	Various	Various	0	714	714	4,810		(gp)(984)	3,826
113	The Energy Authority Inc.	Not Available	Not Available	NF	OATT	Various	Various	0	7,846	7,846	56,696		(gq)(156)	56,540
114	TransAlta Energy Marketing U.S. Inc.	Not Available	Not Available	NF	OATT	Various	Various	0	6,323	6,323	49,743		(gr)(179)	49,564
115	Tucson Electric Power Company	Not Available	Not Available	NF	OATT	Various	Various	0	3,489	3,489	23,533		(gs)13,531	37,064
116	UNIPER GLOBAL COMMODITIES NORTH AMERICA LLC	Not Available	Not Available	NF	OATT	Various	Various	0	214	214	1,704		(gt)(62)	1,642
117	WestConnect	Not Available	Not Available	NF	OATT	Various	Various	0	88,910	88,910	307,205			307,205
118	Western Area Power Administration (DSW)	Not Available	Not Available	NF	OATT	Various	Various	0	0	0			(gu)1	1
119	Yuma Cogeneration Associates	Not Available	Not Available	NF	OATT	Various	Various	0	37	37	670		(gv)(1)	669
120	Arizona Public Service Company	Not Available	Not Available	(u) OLF	RS 183	N/A	N/A	0	1,859,665	1,859,665				
121	PacifiCorp	Not Available	Not Available	(v) OLF	RS 183	N/A	N/A	0	13,363	13,363				
122	Public Service Company of New Mexico	Not Available	Not Available	OLF	RS 73	Palo Verde	Four Corners	130	204,892	204,892	353,758			353,758
123	Yuma Cogeneration Associates	Yuma Cogeneration Assoc.	San Diego Gas and Elect.	OLF	RS 198	Riverside Substation	North Gila Sub	51	953	953	470,732			470,732
124	Imperial Irrigation District	Not Available	Not Available	OS	OATT	N/A	N/A	0	0	0			(gw)13,249	13,249
125	Luke AFB Main Field	DOE WAPA Lower	Luke Air Force Base	OS	RS 162	Pinnacle Peak Sub	Luke Substation	0	0	0	(gx)43,362	317		43,679
126	Marine Corps. Air Station	DOE WAPA Lower	Marine Corps Air Station	OS	RS 166	Gila Substation	Marine Corps Air Stn	0	0	0	(gd)19,413			19,413
127	NOVO BioPower LLC	Not Available	Not Available	OS	OATT	N/A	N/A	0	0	0			(gz)679	679
128	Salt River Project (Schedule F)	Not Available	Not Available	OS	RS 3	N/A	N/A	0	0	0	(ge)2,538			2,538
129	Salt River Project (Schedule Q)	Pinnacle Peak	Ocotillo 230	OS	RS 3	Pinnacle Peak	Ocotillo 230	0	0	0			(gv)233,996	233,996
130	Unit B Irrigation and Drainage District	Not Available	Not Available	OS	RS 181	Gila Substation	District Customer	0	0	0	(af)135			135
131	Yuma Mesa Irrigation and Drainage District	DOE WAPA Lower	Yuma-Mesa Irrigation Dist	OS	RS 31	Gila Substation	Yuma Mesa Load	0	0	0	(gg)1,500			1,500
132	Navajo Transitional Energy Company, LLC	Not Available	Not Available	OS	RS 291	N/A	N/A	0	0	0		117,125	(gz)7,776	124,901
133	Other	Not Available	Not Available	AD	Not Available	Not Available	Not Available	0	0	0			(ga)2,636,830	2,636,830
35	TOTAL							2,011	11,424,450	11,424,450	24,164,674	209,940	5,051,081	29,425,695

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

Network Integration Transmission Service

(b) Concept: StatisticalClassificationCode

Network Integration Transmission Service

(c) Concept: StatisticalClassificationCode

Network Integration Transmission Service

(d) Concept: StatisticalClassificationCode

Network Integration Transmission Service

(e) Concept: StatisticalClassificationCode

Network Integration Transmission Service

(f) Concept: StatisticalClassificationCode

Network Integration Transmission Service

(g) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 167MW, expires on 5/1/2047

(h) Concept: StatisticalClassificationCode

Firm Transmission Service Contracts for 72MW and 58MW, expires on 1/1/2048 and 5/1/2047, respectively

(i) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 120MW, expires 11/15/2051

(j) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 51MW, expires 12/1/2051

(k) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 300MW, expires 1/1/2023

(l) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 90MW, expires 5/31/2025

(m) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 200MW, expires 4/1/2049

(n) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 10MW and 4MW, expires 1/1/2028 and 10/19/2031, respectively

(o) Concept: StatisticalClassificationCode

Firm Transmission Service Contracts for 145MW, expiring 1/1/2023 and 1/1/2024

(p) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 63MW and 64MW, expiring 1/1/2025 and 1/1/2027, respectively

(q) Concept: StatisticalClassificationCode

Firm Transmission Service Contract, transfer from CSEO1 effective 01/03/2022

(r) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 132MW, expiring 12/1/2051

(s) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 2MW, expiring 9/1/2022

(t) Concept: StatisticalClassificationCode

Firm Transmission Service Contract for 110MW, expriring 8/1/2026

(u) Concept: StatisticalClassificationCode

Exchange agreement pursuant to Pre888 contract
(v) Concept: StatisticalClassificationCode
Exchange agreement pursuant to Pre888 contract
(w) Concept: BillingDemand
Service to Arizona Public Service Company pursuant to Part III of the OATT
(x) Concept: BillingDemand
Service to Arizona Public Service Company pursuant to Part III of the OATT
(y) Concept: BillingDemand
Service to Arizona Public Service Company pursuant to Part III of the OATT
(z) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Resale Credits
(aa) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Resale Credits
(ab) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Resale Credits
(ac) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Part of APS NITS load - recovery of transmission cost contract
(ad) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Part of APS NITS load - recovery of transmission cost contract
(ae) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Part of APS NITS load - recovery of transmission cost contract
(af) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Part of APS NITS load - recovery of transmission cost contract
(ag) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
Part of APS NITS load - recovery of transmission cost contract
(ah) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ai) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Credit
(aj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Credit
(ak) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(al) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges, Unreserved Use Penalty/Credit
(am) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Credit
(an) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ao) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ap) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit

(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(at) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges and Unreserved Use Credit
(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(ba) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(bh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(bj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(bk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Unreserved Use Penalty
(bq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(br) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(bt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(bu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges, Unreserved Use Penalty/Credit
(bw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(bx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(by) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(bz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ca) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ce) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ch) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ci) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(ck) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit

(cn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(co) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(cp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty/Credit
(cq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Penalty
(ct) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Unreserved Use Credit
(cw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges
(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges
(cy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Direct Assignment Charges
(cz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
BA Services Administrative Fees
(da) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
FERC Transmission rate true up, change in estimate, and timing difference

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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19					
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28					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	(a) Arizona Public Service Co	LFP			74,057			74,057
2	Bureau of Indian Affairs	(b) OLF			38,400			38,400
3	Department of Energy	(c) OS	4,547	4,547		240,965	(d) 27,169	268,134
4	Department of Energy	NF	106,207	106,207	52,529	12,307	(e) (8,564)	56,272
5	Department of Energy	FNS	83,808	83,808	327,564	60,910	(e) 4,143	392,617
6	Department of Energy	FNS	233,352	233,352	1,267,658	394,666	(e) 69,933	1,732,257
7	Department of Energy	(g) LFP	80,443	80,443		161,261	(f) 57,188	218,449
8	Department of Energy	(g) LFP	89,801	89,801	2,286,569	185,320	(g) 48,819	2,520,708
9	Department of Energy	(f) OS			22,992			22,992
10	Department of Energy	SFP	4,362	4,362	10,865	2,520	(f) (1,768)	11,617
11	Electric District # 3	(g) LFP	639	639	21,595		(g) 2,100	23,695
12	Electric District # 4	(b) OLF	477	477	14,366		(g) (h) (370)	13,996
13	Salt River Project	(i) FNS	7,497	7,497	632	13,266	(g) (3,027)	10,871
14	Salt River Project	(i) OLF	71,663	71,663	383,320	118,507	(g) (h) (118,507)	383,320
15	Salt River Project	LFP	17,390	17,390	533,096	23,411	(aa) (ab) 190,007	(ac) 746,514
16	Salt River Project	(k) FNS	100,308	100,308	98,425	179,075	(ac) (36,580)	240,920

17	Salt River Project	OLF	24,379	24,379	77,563	43,264	[ad](43,264)	77,563
18	Salt River Project	[l] OS	349,940	349,940		163,484	[ae]267,114	430,598
19	Salt River Project	FNS	91,751	91,751	671,307	(155,730)		515,577
20	Southern California Edison	LFP	27,068	27,068	50,130		[af]1,191	51,321
21	Southwest Transmission Cooperative Inc.	SFP	10,240	10,240	51,908		[ag](6,857)	45,051
22	Tucson Electric Power	[m] NF	166	166	1,060	410	(194)	1,276
23	SRP Misc Accounts Receivable	OS	75	75	596	62	(87)	571
24	Navopache Electric Cooperative	OS			80,688			80,688
25	Navopache Electric Cooperative	OS	5,520	5,520		382,614	[ah]74,882	457,496
	TOTAL		1,309,633	1,309,633	6,065,320	1,826,312	523,328	8,414,960

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Intercompany Transmission

(b) Concept: StatisticalClassificationCode

Terminates with 30 days notice

(c) Concept: StatisticalClassificationCode

Loss compensation on jointly owned facilities

(d) Concept: StatisticalClassificationCode

Terminates September 30, 2029

(e) Concept: StatisticalClassificationCode

Terminates December 31, 2022

(f) Concept: StatisticalClassificationCode

Terminates September 30, 2029

(g) Concept: StatisticalClassificationCode

Effective until terminated by counterparty

(h) Concept: StatisticalClassificationCode

Terminates January 1, 2024

(i) Concept: StatisticalClassificationCode

Terminates with 5 year notice

(j) Concept: StatisticalClassificationCode

Terminates May 1, 2023

(k) Concept: StatisticalClassificationCode

Loss compensation for deliveries to DV

(l) Concept: StatisticalClassificationCode

Terminates September 30, 2037

(m) Concept: StatisticalClassificationCode

Navopache Vernon Tie Facilities use charges

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(q) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(r) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(s) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(t) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(u) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(v) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment /Timing

(w) Concept: OtherChargesTransmissionOfElectricityByOthers
Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.
(x) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(y) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(z) Concept: OtherChargesTransmissionOfElectricityByOthers
Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.
(aa) Concept: OtherChargesTransmissionOfElectricityByOthers
Other dollars are EIM sub-allocation dollars as well as prior period adjustment/timing.
(ab) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ac) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ad) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ae) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(af) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ag) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ah) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment /Timing
(ai) Concept: ChargesForTransmissionOfElectricityByOthers
APS payment as a credit on APS provides SRP in the same contract

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

Deprec, Depl and Amort of Elec Plant (403,403.1,404,and 405) (except Amortization of Acquisition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			40,002,810		40,002,810
2	Steam Production Plant	54,879,689	4,542,831	1,777		59,424,297
3	Nuclear Production Plant	6,603,482	(376,143)	1,861,714		8,089,053
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	69,329,941	503,240			69,833,181
7	Transmission Plant	31,999,361		4,118,185		36,117,546
8	Distribution Plant	92,931,936		742,659		93,674,595
9	General Plant	32,734,390		8,261,947		40,996,337
10	Common Plant-Electric					
11	TOTAL	288,478,799	4,669,928	54,989,092		348,137,819

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	6,459,704	27,524,322		
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(7,690,315)	(22,570,804)		
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	CAISO Non Purchases (Account 555)	646,032	1,845,506		
46	TOTAL	(584,579)	6,799,024		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

Monthly Peak Loads and Energy Output

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	Monthly Peak Megawatts (See Instr. 4) (d)	Monthly Peak Day of Month (e)	Monthly Peak Hour (f)
	NAME OF SYSTEM: Arizona Public Service Company					
1	January	2,488,173	230,960	4,207	3	8
2	February	2,158,651	176,769	4,263	24	8
3	March	2,399,104	320,134	3,796	27	19
4	Total for Quarter 1	7,045,928	727,863			
5	April	2,339,140	179,794	4,352	26	18
6	May	2,834,398	159,291	5,820	26	18
7	June	3,636,079	231,599	7,001	10	18
8	Total for Quarter 2	8,809,617	570,684			
9	July					
10	August					
11	September					
12	Total for Quarter 3					
41	Total					

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: Arizona Public Service Company									
1	January	6,164	3	8	4,245	149	1,589	181		
2	February	6,216	24	8	4,267	179	1,589	181		
3	March	5,705	27	19	3,764	171	1,589	181		
4	Total for Quarter 1				12,276	499	4,767	543		
5	April	6,263	26	18	4,300	193	1,589	181		
6	May	7,775	26	18	5,775	230	1,589	181		
7	June	9,177	10	18	6,956	251	1,789	181		
8	Total for Quarter 2				17,031	674	4,967	543		
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total				29,307	1,173	9,734	1,086		

Name of Respondent: Arizona Public Service Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 08/26/2022	Year/Period of Report End of: 2022/ Q2

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Arizona Public Service Company									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

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ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE F-1
TOTAL COMPANY
PRESENT RATES AND WITH PROPOSED RATE INCREASE
TEST YEAR ENDED JUNE 30, 2022 AND PROJECTED YEARS
(Thousands of Dollars)

Line No.	Description	Test Year (a)	Projected Years (b)					Line No.
		Test Year Ended 6/30/2022 (a)	Present Rates Year Ended 12/31/2022 (b)	Present Rates Year Ended 12/31/2023 (b)	Present Rates Year Ended 12/31/2024 (b)	Proposed Rates Year Ended 12/31/2023 (b) ***	Proposed Rates Year Ended 12/31/2024(b)	
		(A)	(B)	(C)	(D)	(E)	(F)	
1.	Electric operating revenues	$ 3,981,825	$ 4,117,798	$ 4,396,264	$ 4,635,062	$ 4,424,426	$ 5,124,336	1.
2.	Fuel and purchased power	1,335,138	1,503,316	1,637,909	1,816,338	1,639,167	1,839,662	2.
3.	Operating revenues less fuel and purchased power	2,646,687	2,614,482	2,758,355	2,818,724	2,785,259	3,284,674	3.
	Other Operating Expenses:							
4.	Operations and maintenance excluding fuel and purchased power *	829,446	961,115	988,621	1,013,860	991,591	1,049,504	4.
5.	Depreciations and amortization	703,703	751,203	777,155	825,907	777,155	825,907	5.
6.	Income taxes	115,485	68,736	80,587	73,978	85,933	184,023	6.
7.	Taxes other than income taxes	253,435	226,661	229,832	232,165	229,832	232,165	7.
8.	Operating income	744,618	606,768	682,160	672,814	700,748	993,076	8.
	Other Income (Deductions):							
9.	Income taxes	6,122	(16,743)	16	2,171	(162)	2,210	9.
10.	Allowance for equity funds used during construction	44,373	46,380	42,936	40,708	42,936	40,708	10.
11.	Other income	25,759	104,397	51,313	48,685	52,033	48,529	11.
12.	Other expenses	(20,096)	(12,945)	(13,489)	(13,463)	(13,489)	(13,463)	12.
13.	Total	56,158	121,089	80,776	78,101	81,318	77,985	13.
14.	Income before interest deductions	800,776	727,857	762,936	750,915	782,066	1,071,061	14.
	Interest Expense							
15.	Interest Charges	250,332	270,404	313,490	334,638	315,807	322,999	15.
16.	Allowance for borrowed funds used during construction	(20,970)	(21,781)	(20,365)	(19,313)	(20,365)	(19,313)	16.
17.	Total	229,362	248,622	293,126	315,325	295,442	303,686	17.
18.	Net Income	$ 571,414	$ 479,234	$ 469,810	$ 435,590	$ 486,624	$ 767,375	18.
19.	Earnings per Share of Average Common Stock Outstanding **	$ 8.02	N/A	N/A	N/A	N/A	N/A	19.
20.	Total Company Return on Average Common Equity	8.7%	7.1%	6.7%	5.9%	7.0%	10.2%	20.
21.	Total Company Average Common Equity	6,540,528	6,755,629	6,987,238	7,350,358	6,995,660	7,508,157	21.
22.	Total Company Return on Year End Common Equity	8.4%	7.0%	6.6%	5.7%	6.8%	9.7%	22.
23.	Total Company End of Period Common Equity	6,786,040	6,876,045	7,098,432	7,602,283	7,115,265	7,901,048	23.
24.	ACC Jurisdictional Return on Year End Common Equity	8.2%	6.2%	5.9%	4.9%	6.2%	9.7%	24.

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs.
** Line 19 is calculated using the common stock shares of Arizona Public Service Company. APS's common stock shares have remained constant at 71.3 million, and are wholly owned by Pinnacle West Capital Corporation. Pinnacle West's common stock is publicly held and the PNW share count is more indicative of the increasing equity investment needed to support APS's investment to serve its customers. APS's earnings per share of Pinnacle West diluted common stock outstanding was $4.84 for the test year ended 6/30/2022.
*** Proposed Rates for year-end 12/31/2023 includes 1 month of proposed rates, as assumed effective date is 12/1/2023

Supporting Schedules:
(a) E-2 and C-1

Recap Schedules:
(b) A-2

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE F-2
PROJECTED CHANGES IN FINANCIAL POSITION
TOTAL COMPANY
PRESENT RATES AND WITH PROPOSED RATE INCREASE
TEST YEAR ENDED JUNE 30, 2022 AND PROJECTED YEARS
(Thousands of Dollars)

Line No.	Description	Test Year (a)	Projected Years (b)					Line No.
		Test Year Ended 6/30/2022 (a)	Present Rates Year Ended 12/31/2022 (b)	Present Rates Year Ended 12/31/2023 (b)	Present Rates Year Ended 12/31/2024 (b)	Proposed Rates Year Ended 12/31/2023 (b) **	Proposed Rates Year Ended 12/31/2024 (b)	
		(A)	(B)	(C)	(D)	(E)	(F)	
	Cash Flows from Operating Activities:							
1.	Net Income	$ 571,414	$ 479,234	$ 469,810	$ 435,590	$ 486,624	$ 767,375	1.
	Items Not Requiring Cash:							
2.	Depreciation and amortization including nuclear fuel	769,598	811,373	833,603	881,379	833,603	881,379	2.
3.	Allowance for equity funds used during construction	(44,373)	(46,380) (c)	(42,936) (c)	(40,708) (c)	(42,936) (c)	(40,708) (c)	3.
4.	Deferred income taxes	101,698	45,297	128,855	17,392	132,084	8,042	4.
5.	Deferred fuel and purchased power	(219,676)	219,002	332,911	496,274	317,175	285,187	5.
6.	Deferred fuel and purchased power amortization	130,571	(279,705)	(297,346)	(296,615)	(280,353)	(62,202)	6.
7.	Other (SFR E-3 Lines 7-18)	(176,519)	58,019	(10,347)	(8,625)	(10,240)	(7,923)	7.
8.	Net cash flow provided by operating activi ies	1,132,713	1,286,840	1,414,550	1,484,689	1,435,957	1,831,149	8.
	Cash Flows from Inves ing Activities:							
9.	Capital expenditures *	(1,618,214)	(1,557,752)	(1,525,093)	(1,643,201)	(1,525,093)	(1,643,201)	9.
10.	Contributions in aid of construction *	142,642	-	-	-	-	-	10.
11.	Allowance for borrowed funds used during construction	(20,970)	(21,781) (c)	(20,365) (c)	(19,313) (c)	(20,365) (c)	(19,313) (c)	11.
12.	Net (Increase) Decrease in Receivables	(213)	-	-	-	-	-	12.
13.	Net Increase (Decrease) in Payables and Accrued Expenses	518	-	-	-	-	-	13.
14.	Proceeds from nuclear decommissioning trust sales and other special use funds	1,825,310	-	-	-	-	-	14.
15.	Investment in nuclear decommissioning trust and other special use funds	(1,829,309)	(25,567)	(32,631)	(32,031)	(32,631)	(32,031)	15.
16.	O her	(2,148)	-	-	-	-	-	16.
17.	Net cash flow used for inves ing activities	(1,502,384)	(1,605,100)	(1,578,089)	(1,694,545)	(1,578,089)	(1,694,545)	17.
	Cash Flows from Financing Activities:							
18.	Issuance of long-term debt	446,999	628,000	500,000	500,000	550,000	100,000	18.
19.	Repayment of long-term debt	-	-	-	(250,000)	-	(250,000)	19.
20.	Short-term borrowings and (repayments)-net	20,000	(80,727)	(89,039)	(108,405)	(160,454)	(5,012)	20.
21.	Dividends paid on common stock	(381,500)	(388,387)	(397,423)	(406,739)	(397,414)	(406,591)	21.
22.	Equity infusion from Pinnacle West	300,000	150,000	150,000	475,000	150,000	425,000	22.
23.	Net cash flow used for financing activities	385,499	308,886	163,539	209,856	142,132	(136,603)	23.
24.	Net (decrease) increase in cash and cash equivalents	15,828	(9,374)	0	0	0	0	24.
25.	Cash and cash equivalents at beginning of year	11,954	9,374	0	0	0	0	25.
26.	Cash and cash equivalents at end of year	$ 27,782	0	0	0	0	0	26.

Notes:
* For future years capital expenditures are shown after contribu ions in aid of construction on a cash basis.
There may be variances in displayed values due to rounding.
** Proposed Rates for year-end 12/31/2023 includes 1 month of proposed rates, as assumed effective date is 12/1/2023

Supporting Schedules:
(a) E-3
(c) F-3

Recap Schedules:
(b) A-5

NOTE: There may be variances in displayed values die to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENTS SCHEDULE F-3
PROJECTED CAPITAL EXPENDITURES
TOTAL COMPANY
YEAR TO DATE 6/30/2022 AND PROJECTED YEARS
(Thousands of Dollars)

Line No.	Description	Year to Date 06/30/2022 (A)	Projected Years Year Ended 12/31/2022 (B)	Year Ended 12/31/2023 (C)	Year Ended 12/31/2024 (D)	Line No.
	Electric:					
1.	Production Plant:	$265,436	$584,941	$602,371	$755,164	1.
2.	Transmission:	92,710	212,271	208,361	208,385	2.
3.	Distribution:	281,770	559,643	527,262	497,515	3.
4.	General:	87,035	162,415	183,067	184,918	4.
5.	Total Construction Expenditures (a) *	726,951	1,519,269	1,521,061	1,645,982	5.
6.	Property Taxes Capitalized	2,708	5,731	3,939	4,018	6.
7.	Capital Expenditures	729,659	1,525,000	1,525,000	1,650,000	7.
8.	Allowance for Equity Funds Used During Construction	44,373	46,380 (b)	42,936 (b)	40,708 (b)	8.
9.	Allowance for Borrowed Funds Used During Construction	20,970	21,781 (b)	20,365 (b)	19,313 (b)	9.
10.	Total Capital Expenditures with AFUDC	$ 795,002	$ 1,593,162	$ 1,588,301	$ 1,710,021	10.

Notes:
* Construction expenditures are reflected on an accrual basis.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-4
(b) F-2

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENTS SCHEDULE F-4
ASSUMPTIONS USED IN DEVELOPING PROJECTED PERIODS
ENDING DECEMBER 2022, 2023 & 2024

Line No.	Item		Line No.
	A.	Customer Growth:	
1.		Retail customer growth for the three-year period ending December 2024 is forecasted to grow at an annual average rate of 1.9%.	1.
	B.	Growth in Retail Energy and Retail Peak Demand	
2.		Retail energy sales, assuming normal weather, for the three-year period ending December 2024 are forecasted to grow at an average	2.
3.		annual rate of 0.6%, excluding data centers. Growth from new large data center customers is included in sales and revenue starting	3.
4.		in 2021. Retail Own Load summer peak demand for the same period is projected to grow at an average annual rate of 2.8%, assuming	4.
5.		normal weather. Sales growth also reflects the impact of the Company's Energy Efficiency and Distr buted Energy programs.	5.
	C.	Wholesale and Economy Interchange Sales	
6.		Firm wholesale sales and peak demand for requirement-to-serve customers are forecasted in accordance with existing contracts. The	6.
7.		Company also sells energy on a short-term basis from time to time. Such sales are made at prices above the Company's	7.
8.		variable costs.	8.
	D.	Regulatory	
9.		The Proposed Rates case assumes new rates are effective on December 1, 2023. The Commission allows APS to pass	9.
10.		through changes in the transmission costs charged to retail customers once approved by the Federal Energy Regulatory	10.
11.		Commission (FERC). The Proposed Rates case assumes full or partial transfers from several adjustors to base rates as of the	11.
12.		rate effective date, including the Lost Fixed Cost Recovery mechanism (LFCR), the Environmental Improvement Surcharge (EIS),	12.
13.		and the Demand Side Management Adjustment Charge (DSMAC). Additionally, the Renewable Energy Adjustment Charge (REAC)	13.
14.		adjustor is increased in the Proposed Rates case to cover the Coal Communities Transition (CCT) request starting on	14.
15.		the proposed rate effective date.	15.
	E.	Base Fuel Charge, PSA & PCCF Revenues	
16.		The Present Rates case Base Fuel Charge reflects 3.1451 cents/kWh consistent with Decision No. 78317. The Proposed Rates	16.
17.		case assumes PSA annual adjustor charges are in effect and a new forward component is set each year reflecting that year's anticipated	17.
18.		fuel and purchased power costs which differ from the Base Fuel Rate. The forward component is reset annually with the first billing	18.
19.		cycle in February. Starting February 1, 2022 the PSA charge is 0.7544 cents/kWh, and subsequent increases to the	19.
20.		PSA charge are included in 2023 and 2024 with each PSA reset. The proposed base fuel rate increases to 3.8321 cents/kWh	20.
21.		beginning December 2023, with a concurrent reduction to the PSA rate.	21.
	F.	Fuel	
22.		Fuel costs are based on projected sales, forward contract and market fuel prices, and projected operating availability factors	22.
23.		of power plants. Fuel costs reflect use of the PSA Mechanism as approved in Decision No. 78317 in the Present Rates case.	23.
	G.	Operations & Maintenance Expenses	
24.		Growth in Operations and Maintenance expense is managed to remain below the expected rate of inflation. Managed growth rates	24.
25.		exclude generation plant outages and Renewable Energy Surcharge (RES) and Demand Side Management (DSM) program costs.	25.
	H.	Construction Expenditures	
26.		The level of expenditures is primarily driven by customer, sales, and load growth, maintaining reliability, legal and regulatory	26.
27.		requirements, environmental requirements, and the Arizona Sun program. Contributions in aid of construction (CIAC)	27.
28.		are normally used to reduce capital expenditures. *See* SFR Schedule F-3 for expenditure table.	28.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENTS SCHEDULE F-4
ASSUMPTIONS USED IN DEVELOPING PROJECTED PERIODS
ENDING DECEMBER 2022, 2023 & 2024

Line No.	Item		*Line No.*
	I.	Depreciation	
29.		In both the Present Rates case and the Proposed Rates case, depreciation expense starting December 1, 2021 includes 10 year amortization	*29.*
30.		of deferral balances for approved costs deferred through January 1, 2021 on Four Corners SCRs and the Ocotillo Modernization Project (OMP).	*30.*
31.		In both the Present Rates case and the Proposed Rates case, depreciation expense starting August 1, 2023 includes 10 year amortization	*31.*
32.		of deferral balances for all expenses deferred from December 31, 2020 through December 1, 3021 on Four Corners SCRs and the OMP.	*32.*
	J.	Capital Structure Changes	
33.		Capital Structure and Financing are shown on Schedules A-3, D-1, D-2, D-4 and F-2.	*33.*
	K.	Financing	
34.		Forecasted Interest Rates: Pollution Control Bonds - 2.60% in 2022, 2.78% in 2023, 2.72% in 2024	*34.*
35.		Commercial Paper - 1.68% in 2022, 3.13% in 2023, 2.94% in 2024	*35.*
36.		New Long-Term Unsecured Debt - 5.75% in 2022, 5.75% in 2023, 5.75% in 2024	*36.*
37.		Present Rates include an infusion of $150 million of equity into APS by its parent company in 2022 and includes possible equity	*37.*
38.		infusions of $150 million in 2023 and $475 million in 2024. Proposed Rates assume $50 million lower equity infusion needs in 2024 than in Present Rates.	*38.*

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-1
COST OF SERVICE SUMMARY - *PRESENT RATES*
RATES OF RETURN BY CUSTOMER
CLASSIFICATION ADJUSTED TEST YEAR ENDED
JUNE 30, 2022
(Thousands of Dollars)

Line No.		Total Company	Total ACC Jurisdictional	All Other	Total ACC Jurisdictional: Residential	General Service	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
1.a.	Revenues from Base Rates	$ 3,447,394	$ 3,376,812 (a)	70,582	1,819,309 (a)	1,499,082 (a)	30,336 (a)	- (a)	19,298 (a)	8,787 (a)	1.a.
1.b.	Revenues from Surcharges	-	-	-	-	-	-	-	-	-	1.b.
1.c.	Other Electric Revenues	303,637	251,851	51,786	$ 130,292	118,081	2,457	-	864	157	1.c.
2.	Expenses	3,352,837	3,417,889 (b)	(65,052)	1,966,050 (b)	1,404,306 (b)	29,508 (b)	- (b)	12,869 (b)	5,157 (b)	2.
3.	Operating Income Before Income Taxes	398,194	210,774	187,419	(16,449)	212,857	3,286	0	7,292	3,788	3.
4.	Income Taxes	1,735	-27,077	28,812	(56,437)	27,178	304	-	1,243	634	4.
5.	Net Operating Income	$ 396,458	$ 237,851	$ 158,607	$ 39,989	$ 185,679	$ 2,981	$ -	$ 6,048	$ 3,154	5.
6.	Rate Base	$ 13,146,361	$ 10,515,874 (c)	2,630,487	7,067,030 (c)	3,269,593 (c)	67,153 (c)	- (c)	72,262 (c)	39,835 (c)	6.
7.	Rate of Return	3 02%	2 26%	6 03%	0 57%	5 68%	4.44%	0.00%	8.37%	7.92%	7.

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-2
COST OF SERVICE SUMMARY - *PROPOSED RATES*
RATES OF RETURN BY CUSTOMER
CLASSIFICATION ADJUSTED TEST YEAR ENDED
JUNE 30, 2022
(Thousands of Dollars)

Line No.		Total Company	Total ACC Jurisdictional	All Other	Total ACC Jurisdictional: Residential	General Service	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
1.a.	Revenues from Base Rates	$ 4,136,886	$ 4,066,304 [1]	70,582	2,178,938 [1]	1,817,016 [1]	38,165 [1]	- [1]	22,338 [1]	9,847 [1]	1.a.
1.b.	Revenues from Surcharges	-	-	-	-	-	-	-	-	-	1.b.
1.c.	Other Electric Revenues	303,637	251,851	51,786	$ 130,292	118,081	2,457	-	864	157	1.c.
2.	Expenses	3,352,837	3,417,889 (b)	(65,052)	1,966,050 (b)	1,404,306 (b)	29,508 (b)	- (b)	12,869 (b)	5,157 (b)	2.
3.	Operating Income Before Income Taxes	1,087,686	900,266	187,419	343,180	530,791	11,115	0	10,332	4,848	3.
4.	Income Taxes	175,091	146,278	28,812	33,982	107,115	2,273	-	2,008	901	4.
5.	Net Operating Income	$ 912,595	$ 753,988	$ 158,607	$ 309,199	$ 423,676	$ 8,842	$ -	$ 8,324	$ 3,947	5.
6.	Rate Base	$ 13,146,361	$ 10,515,874 (c)	2,630,487	7,067,030 (c)	3,269,593 (c)	67,153 (c)	- (c)	72,262 (c)	39,835 (c)	6.
7.	Rate of Return	6 94%	7.17%	6.03%	4.38%	12.96%	13.17%	0.00%	11.52%	9.91%	7.

Schedule H-1 Base Revenue Reconciliation

		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn	
8.	Revenues from Present Rates	$ 3,447,394	$ 3,376,812	$ 70,582	$ 1,819,311	$ 1,499,081	$ 30,336	$ -	$ 19,297	$ 8,787	8.
9.	Revenue Increase from Proposed Rates (excluding Fair Value)*	689,492	689,492	-	359,627	317,935	7,829	-	3,041	1,060	9.
10.	Revenue Increase from Fair Value	82,780	82,780	-	55,075	26,303	541	-	558	303	10.
11.	Subtotal of Revenue Increase	772,272	772,272	-	414,702	344,238	8,370	-	3,599	1,363	11.
12.	Total Proposed Base Revenues	$ 4,219,666	$ 4,149,084 (a)	$ 70,582	$ 2,234,013 (a)	$ 1,843,319 (a)	$ 38,706 (a)	$ - (a)	$ 22,896 (a)	$ 10,150	12.

Notes:
* Proposed Rates allocated based on Total Proposed Increase - Column (c) Schedule H-1.
[1] Total Proposed Base Revenues (Row 12) less Revenue Increase from Fair Value (Row 10)

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-3
RATE BASE ALLOCATIONS TO CLASSES OF SERVICE
TOTAL RATE BASE
ADJUSTED TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
1.	Residential	3,499,296	-	-	414,012	437,161	220,960	1,424,828	490,051	6,486,307	64.23%	77,985	50.57%	1.
2.	General Service	2,562,554	-	-	234,905	154,344	-	432,315	126,220	3,510,338	34.76%	74,025	48.00%	2.
3.	Irrigation - Non Agriculture	46,069	-	-	5,268	3,139	-	8,794	3,872	67,143	0.66%	1,538	1.00%	3.
4.	Irrigation - Agriculture	-	-	-	-	-	-	-	-	-	0.00%	-	0.00%	4.
5.	Street Lighting	11,614	-	-	2,796	1,819	864	5,879	1,350	24,322	0.24%	574	0.37%	5.
6.	Dusk to Dawn	1,995	-	-	541	1,708	162	4,930	1,667	11,003	0.11%	103	0.07%	6.
		6,121,528 (b)	-	-	657,522 (b)	598,171 (b)	221,986 (b)	1,876,745 (b)	623,160 (b)	10,099,113	100.00%	154,225 (b)	100.00%	

	Class of Service	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %	
		(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	
7.	Residential	(70,643)	55,441	199,688	325,466	159,742	-	-	12,989	43,719	726,403	103.06%	7.
8.	General Service	(273,112)	8,995	60,974	75,649	18,474	-	-	1,502	5,056	#######	-14.54%	8.
9.	Irrigation - Non Agriculture	(617)	118	1,031	2,126	166	-	-	14	45	2,883	0.41%	9.
10.	Irrigation - Agriculture	-	-	-	-	-	-	-	-	-	-	0.00%	10.
11.	Street Lighting	(945)	-	-	-	206	-	49,678	17	56	49,012	6.95%	11.
12.	Dusk to Dawn	(0)	-	-	-	1,084	27,556	-	88	297	29,024	4.12%	12.
		(345,317) (b)	64,554 (b)	261,694 (b)	403,241 (b)	179,671 (b)	27,556 (b)	49,678 (b)	14,610 (b)	49,174 (b)	704,860 (b)	100.00%	

	Class of Service	Total System Benefits	Total System Benefits %	TOTAL ACC Jurisdictional (a)	TOTAL ACC Jurisdictional %	
		(X)	(Y)	(Z)	(AA)	
13.	Residential	(223,665)	50.57%	7,067,030	67.20%	13.
14.	General Service	(212,307)	48.00%	3,269,593	31.09%	14.
15.	Irrigation - Non Agriculture	(4,411)	1.00%	67,153	0.64%	15.
16.	Irrigation - Agriculture	-	0.00%	-	0.00%	16.
17.	Street Lighting	(1,646)	0.37%	72,262	0.69%	17.
18.	Dusk to Dawn	(295)	0.07%	39,835	0.38%	18.
		(442,325) (b)	100.00%	10,515,874	100.00%	

Supporting Schedules:
(b) G-5
(c) G-7

Recap Schedules:
(a) G-1 & G-2

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-4
EXPENSE ALLOCATION TO CLASSES OF SERVICE
OPERATING EXPENSES EXCLUDING INCOME TAXES
ADJUSTED TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Distribution Demand - Rents	Total Demand	Total Demand %	Total Energy	Total Energy %	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	Residential	538,393	-	155,323	39,038	48,620	24,936	116,598	38,931	3,128	964,969	60.16%	741,359	51.39%	1.
2.	General Service	396,012	-	137,941	22,555	18,119	-	35,378	10,027	1,104	621,136	38.72%	682,331	47.30%	2.
3.	Irrigation - Non Agriculture	7,310	-	4,550	506	369	-	720	308	22	13,784	0.86%	13,281	0.92%	3.
4.	Irrigation - Agriculture	-	-	-	-	-	-	-	-	-	-	0.00%	-	0.00%	4.
5.	Street Lighting	1,726	-	112	268	214	105	481	107	13	3,026	0.19%	4,728	0.33%	5.
6.	Dusk to Dawn	260	-	18	52	194	20	403	132	12	1,091	0.07%	891	0.06%	6.
		943,700 (a)	-	297,944	62,420 (a)	67,515 (a)	25,060 (a)	153,580 (a)	49,506 (a)	4,280 (a)	1,604,006	100.00%	1,442,590 (a)(b)	100.00%	

	Class of Service	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %	
		(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	
7.	Residential	6,287	16,431	85,190	85,192	-	-	32,228	21,227	246,555	78.98%	7.
8.	General Service	1,020	5,017	19,801	7,161	-	-	20,761	2,455	56,215	18.01%	8.
9.	Irrigation - Non Agriculture	13	85	556	21	-	-	818	22	1,516	0.49%	9.
10.	Irrigation - Agriculture	-	-	-	-	-	-	-	-	-	0.00%	10.
11.	Street Lighting	-	-	-	74	-	4,504	164	27	4,769	1.53%	11.
12.	Dusk to Dawn	-	-	-	591	2,262	-	115	144	3,112	1.00%	12.
		7,320 (a)	21,534 (a)	105,548 (a)	93,040 (a)	2,262 (a)	4,504 (a)	54,085 (a)	23,875	312,168	100.00%	

	Class of Service	Total System Benefits	Total System Benefits %	Limited Income Discount	Limited Income Discount %	TOTAL ACC Jurisdictional (a)	TOTAL ACC Jurisdictional %	
		(X)	(Y)	(Z)	(AA)	(BB)	(CC)	
13.	Residential	47,011	50.57%	(33,844)	100.00%	1,966,050	57.52%	13.
14.	General Service	44,624	48.00%	-	0.00%	1,404,306	41.09%	14.
15.	Irrigation - Non Agriculture	927	1.00%	-	0.00%	29,508	0.86%	15.
16.	Irrigation - Agriculture	-	0.00%	-	0.00%	-	0.00%	16.
17.	Street Lighting	346	0.37%	-	0.00%	12,869	0.38%	17.
18.	Dusk to Dawn	62	0.07%	-	0.00%	5,157	0.15%	18.
		92,969 (a)	100.00%	(33,844) (a)	100.00%	3,417,889 (c)	100.00%	

Supporting Schedules:
(a) G-6
(b) G-7

Recap Schedules:
(c) G-1 & G-2

NOTE: There may be variances in displayed figures due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-5
DISTRIBUTION OF RATE BASE BY FUNCTION
TOTAL RATE BASE
ADJUSTED TEST YEAR ENDED JUNE 30, 2022
(Thousands of Dollars)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribu ion OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
1.	Production - Demand	$ 6,121,528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,121,528	60.61%	1.
2.	Transmission Substation	-	-	-	-	-	-	-	-	-	0.00%	2.
3.	Transmission Lines	-	-	-	-	-	-	-	-	-	0.00%	3.
4.	Distribution Substation	-	-	-	657,522	-	-	-	-	657,522	6.51%	4.
5.	Distribution OH Primary	-	-	-	-	598,171	-	-	-	598,171	5.92%	5.
6.	Distribu ion OH Secondary	-	-	-	-	-	221,986	-	-	221,986	2.20%	6.
7.	Distribution UG Lines	-	-	-	-	-	-	1,876,745	-	1,876,745	18.58%	7.
8.	Distribution Line TXFs	-	-	-	-	-	-	-	623,160	623,160	6.17%	8.
9.	Total	$ 6,121,528	$ -	$ -	$ 657,522	$ 598,171	$ 221,986	$ 1,876,745	$ 623,160	$ 10,099,113	100.00%	9.

	Plant Classification	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service and Information	Sales	Total Customer	Total Customer %	
		(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	
10.	Cust. Advances & Deposit	$ (345,317)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (345,317)	-48.99%	10.
11.	Distribution OH Services	-	64,554	-	-	-	-	-	-	-	64,554	9.16%	11.
12.	Distribution UG Services	-	-	261,694	-	-	-	-	-	-	261,694	37.13%	12.
13.	Distribution Meters	-	-	-	403,241	-	-	-	-	-	403,241	57.21%	13.
14.	Customer Accounts	-	-	-	-	179,671	-	-	-	-	179,671	25.49%	14.
15.	Dusk to Dawn	-	-	-	-	-	27,556	-	-	-	27,556	3.91%	15.
16.	Street Lighting	-	-	-	-	-	-	49,678	-	-	49,678	7.05%	16.
17.	Customer Service and Info	-	-	-	-	-	-	-	14,610	-	14,610	2.07%	17.
18.	Sales	-	-	-	-	-	-	-	-	49,174	49,174	6.98%	18.
19.	Total	$ (345,317)	$ 64,554	$ 261,694	$ 403,241	$ 179,671	$ 27,556	$ 49,678	$ 14,610	$ 49,174	$ 704,860	100.00%	19.

	Plant Classification	Total Energy	Total Energy %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS.		
		(V)	(W)	(X)	(Y)	(Z)		
20.	Production - Energy	$ 154,225	100.00%	$ -	-	$ -		20.
21.	System Benefits	-	-	(442,325)	100.00%	-		21.
22.	TOTAL ACC	-	-	-	-	10,515,874	(a)	22.

Supporting Schedules:
N/A

Recap Schedules:
(a) G-3

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-6
DISTRIBUTION OF EXPENSES BY FUNCTION
OPERATING EXPENSES EXCLUDING INCOME TAXES
ADJUSTED TEST YEAR ENDED 06/30/2022
(Thousands of Dollars)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Distribution Demand - Rents	Total Demand	Total Demand %	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	
1.	Production - Demand	$ 943,700	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 943,700	58 83%	1.
2.	Transmission Substation	-	-	-	-	-	-	-	-		$ -	0 00%	2.
3.	Transmission Lines	-	-	297,944	-	-	-	-	-		$ 297,944	18 57%	3.
4.	Distribution Substation	-	-	-	62,420	-	-	-	-		$ 62,420	3 89%	4.
5.	Distribution OH Primary	-	-	-	-	67,515	-	-	-		$ 67,515	4 21%	5.
6.	Distribution OH Secondary	-	-	-	-	-	25,060	-	-		$ 25,060	1 56%	6.
7.	Distribution UG Lines	-	-	-	-	-	-	153,580	-		$ 153,580	9 57%	7.
8.	Distribution Line TXFs	-	-	-	-	-	-	-	49,506		$ 49,506	3 09%	8.
9.	Distribution Demand - Rents	-	-	-	-	-	-	-	-	4,280	$ 4,280	0 27%	9.
10.	Total	$ 943,700	$ -	$ 297,944	$ 62,420	$ 67,515	$ 25,060	$ 153,580	$ 49,506	$ 4,280	$ 1,604,006	100 00%	10.

	Plant Classification	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service and Information	Sales	Total Customer	Total Customer %	
		(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	
11.	Distribution OH Services	$ 7,320	$ -	$ -	$ -	$ -	$ -	$ -	$ -	7,320	2.35%	11.
12.	Distribution UG Services	-	21,534	-	-	-	-	-	-	21,534	6.90%	12.
13.	Distribution Meters	-	-	105,548	-	-	-	-	-	105,548	33.81%	13.
14.	Customer Accounts	-	-	-	93,040	-	-	-	-	93,040	29.80%	14.
15.	Dusk to Dawn	-	-	-	-	2,262	-	-	-	2,262	0.72%	15.
16.	Street Lighting	-	-	-	-	-	4,504	-	-	4,504	1.44%	16.
17.	Customer Service and Info	-	-	-	-	-	-	54,085	-	54,085	17.33%	17.
18.	Sales	-	-	-	-	-	-	-	23,875	23,875	7.65%	18.
19.	Total	$ 7,320	$ 21,534	$ 105,548	$ 93,040	$ 2,262	$ 4,504	$ 54,085	$ 23,875	$ 312,168	100.00%	19.

	Plant Classification	Total Production - Energy	Total Energy %	Limited Income Discount	Limited Income Discount %	Total System Benefits	Total System Benefits %	TOTAL ACC Jurisdictional (a)		
		(V)	(W)	(X)	(Y)	(Z)	(AA)	(BB)		
20.	Production - Energy	$ 1,442,590	100.00%	$ -	$ -	$ -	-	$ -		20.
21.	Limited Income Discount	-	-	-33,844	100.00%	-	-	-		21.
22.	System Benefits	-	-	-	-	92,969	100.00%	-		22.
23.	TOTAL ACC	-	-	-	-	-	-	3,417,889		23.

Supporting Schedules:
N/A

Recap Schedules:
(a) G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	ELECTRIC TOTAL	ACC JURISDICTIONAL	ALL OTHER	TOTAL RETAIL	RETAIL					
						RESIDENTIAL	GENERAL SERVICE	E-221 (Non AG)	E-221 (AG)	Street Lighting	Dusk to Dawn
		(A)	(B)	©	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	CUSTOMER COUNT ALLOCATORS										
1	CUST371 Dusk to Dawn Customer Class Specific (%)	100	100	-	100	-	-	-	-	-	100
	CUST371 Dusk to Dawn	**100.00%**	**100.00%**	**-**	**100.00%**	**-**	**-**	**-**	**-**	**-**	**100.00%**
2	CUST373 Street Lighting Customer Class Specific (%)	100	100	-	100	-	-	-	-	100	-
	CUST373 Street Lighting	**100.00%**	**100.00%**	**-**	**100.00%**	**-**	**-**	**-**	**-**	**100.00%**	**-**
3	CUST910 Number of Customer Accounts	1,347,256	1,347,256	-	1,347,256	1,197,816	138,523	1,246	-	1,544	8,127
	CUST910 Customer Service and Information	**100.00%**	**100.00%**	**-**	**100.00%**	**88.91%**	**10.28%**	**0.09%**	**0.00%**	**0.11%**	**0.60%**
4	CUST916 Number of Customer Accounts	1,347,261	1,347,256	5	1,347,256	1,197,816	138,523	1,246	-	1,544	8,127
	CUST916 Sales Expense	**100.00%**	**100.00%**	**0.00%**	**100.00%**	**88.91%**	**10.28%**	**0.09%**	**0.00%**	**0.11%**	**0.60%**
5	CUSTNUM Number of Customer Accounts	1,347,261	1,347,256	5	1,347,256	1,197,816	138,523	1,246	-	1,544	8,127
	CUSTNUM Customer Accounts	**100.00%**	**100.00%**	**0.00%**	**100.00%**	**88.91%**	**10.28%**	**0.09%**	**0.00%**	**0.11%**	**0.60%**
6	CUSTNUM_A Number of Customer Accounts ACC	1,347,256	1,347,256	-	1,347,256	1,197,816	138,523	1,246	-	1,544	8,127
	CUSTNUM A Customer Accounts ACC	**100.00%**	**100.00%**	**-**	**100.00%**	**88.91%**	**10.28%**	**0.09%**	**0.00%**	**0.11%**	**0.60%**
	CUSTOMER COST ALLOCATORS										
7	CUST370 Costs for Distribution Meters ($)	$255,031,361	$254,994,938	$36,423	$254,994,938	$205,812,998	$47,837,656	$1,344,284	-	-	-
	CUST370 Distribution Meters	**100.00%**	**99.99%**	**0.01%**	**99.99%**	**80.70%**	**18.76%**	**0.53%**	**0.00%**	**-**	**-**
8	CUSTOH1 Weighted Customer Costs for Distribution Services ($)	$87,767,910	$87,767,910	-	$87,767,910	$75,377,592	$12,229,886	$160,433	-	-	-
	CUSTOH1 Distribution OH Services	**100.00%**	**100.00%**	**-**	**100.00%**	**85.88%**	**13.93%**	**0.18%**	**0.00%**	**-**	**-**
9	CUSTUG1 Weighted Customer Costs for Distribution Services ($)	$574,474,696	$574,474,696	-	$574,474,696	$438,358,760	$133,851,785	$2,264,152	-	-	-
	CUSTUG1 Distribution UG Services	**100.00%**	**100.00%**	**-**	**100.00%**	**76.31%**	**23.30%**	**0.39%**	**-**	**-**	**-**
	DISTRIBUTION DEMAND ALLOCATORS										
10	DEMDIST1 NCP Demand @ Substation Level w/losses (KW)	7,702,469	7,702,469	-	7,702,469	4,849,893	2,751,764	61,717	-	32,755	6,340
	DEMDIST1 Distribution Substation	**100.00%**	**100.00%**	**-**	**100.00%**	**62.97%**	**35.73%**	**0.80%**	**0.00%**	**0.43%**	**0.08%**
11	DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)	7,494,504	7,494,504	-	7,494,504	4,718,946	2,677,467	60,051	-	31,871	6,169
	DEMDIST2 Distribution OH Primary Lines	**100.00%**	**100.00%**	**-**	**100.00%**	**73.08%**	**25.80%**	**0.52%**	**0.00%**	**0.30%**	**0.29%**
12	DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	8,218,000	8,218,000	-	8,218,000	8,180,000	-	-	-	32,000	6,000
	DEMDIST3 Distribution OH Secondary Lines	**100.00%**	**100.00%**	**-**	**100.00%**	**99.54%**	**-**	**-**	**-**	**0.39%**	**0.07%**
13	DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)	7,494,504	7,494,504	-	7,494,504	4,718,946	2,677,467	60,051		31,871	6,169
	DEMDIST4 Distribution UG Primary Lines	**100.00%**	**100.00%**	**-**	**100.00%**	**73.08%**	**25.80%**	**0.52%**	**0.00%**	**0.30%**	**0.29%**
14	DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	8,218,000	8,218,000	-	8,218,000	8,180,000	-	-	-	32,000	6,000
	DEMDIST5 Distribution UG Secondary Lines	**100.00%**	**100.00%**	**-**	**100.00%**	**99.54%**	**-**	**-**	**-**	**0.39%**	**0.07%**
15	DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	10,707,444	10,707,444	-	10,707,444	8,262,626	2,296,434	110,000	-	32,323	6,061
	DEMDIST6 Distribution OH Line Transformers	**100.00%**	**100.00%**	**-**	**100.00%**	**81.75%**	**17.09%**	**0.66%**	**0.00%**	**0.23%**	**0.27%**
16	DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	11,668,105	11,668,105	-	11,668,105	8,262,626	3,257,095	110,000	-	32,323	6,061
	DEMDIST7 Distribution UG Line Transformers	**100.00%**	**100.00%**	**-**	**100.00%**	**77.87%**	**21.04%**	**0.61%**	**0.00%**	**0.21%**	**0.27%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	ELECTRIC TOTAL	ACC JURISDICTIONAL	ALL OTHER	TOTAL RETAIL	RETAIL: RESIDENTIAL	RETAIL: GENERAL SERVICE	RETAIL: E-221 (Non AG)	RETAIL: E-221 (AG)	RETAIL: Street Lighting	RETAIL: Dusk to Dawn
		(A)	(B)	©	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	PRODUCTION DEMAND ALLOCATORS										
17	DEMPROD1 Average & Peak @ Generation (All Other 4CP) (%)	1	1	0	1	1	0	0	0	0	0
	DEMPROD1 Production Demand	**100.00%**	**99.88%**	**0.12%**	**99.88%**	**57.10%**	**41.81%**	**0.75%**	**0.00%**	**0.19%**	**0.03%**
18	DEMPROD6 Specific Assignment	100	-	100	-	-	-	-	-	-	-
	DEMPROD6 Ancillary Service - Scheduling & Dispatch	**100.00%**	**-**	**100.00%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	TRANSMISSION DEMAND ALLOCATORS										
19	DEMTRAN1 Specific Assignment	100	-	100	-	-	-	-	-	-	-
	DEMTRAN1 Transmission Substation	**100.00%**	**-**	**100.00%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
20	DEMTRAN3 Specific Assignment	100	-	100	-	-	-	-	-	-	-
	DEMTRAN3 Transmission Lines	**100.00%**	**-**	**100.00%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
21	DEMTRAN4 4CP @ Generation (KW)	7,308,100	7,299,451	8,649	7,299,451	4,633,776	2,626,742	37,841	-	1,092.00	-
	DEMTRAN4 Transmission	**100.00%**	**99.88%**	**0.12%**	**99.88%**	**63.41%**	**35.94%**	**0.52%**	**0.00%**	**0.00**	**-**
	ENERGY ALLOCATORS										
22	ENERGY1 Customer Class Energy @ Generation including AG-1 (MWH)	32,312,539	32,248,840	63,699	32,248,840	16,306,911	15,478,831	321,566	-	120,042	21,490
	ENERGY1 Production - Energy	**100.00%**	**99.80%**	**0.20%**	**99.80%**	**50.47%**	**47.90%**	**1.00%**	**0.00%**	**0.37%**	**0.07%**
23	ENERGY1_GS General Service Energy @ Generation including AG-1 (MWH)	15,478,831	15,478,831	-	15,478,831	-	15,478,831	-	-	-	-
	ENERGY1 GS General Service Energy	**100.00%**	**100.00%**	**-**	**100.00%**	**-**	**100.00%**	**-**	**-**	**-**	**-**
24	ENERGY2 Weighted Hourly Energy Allocator @ Generation including AG-1 (%)	1	1	0	1	1	0	0	0	0	0
	ENERGY2 Production - Energy (Fuel and Purchased Power)	**100.00%**	**99.80%**	**0.20%**	**99.80%**	**51.53%**	**46.90%**	**0.98%**	**0.00%**	**0.34%**	**0.06%**
25	ENERGY2_XAG1 Weighted Hourly Energy Allocator @ Generation excluding AG-1 (%)	1	1	0	1	1	0	0	0	0	0
	ENERGY2 XAG1 Production - Energy (Fuel and Purchased Power)	**100.00%**	**99.80%**	**0.20%**	**99.80%**	**53.22%**	**45.16%**	**1.01%**	**0.00%**	**0.35%**	**0.06%**
26	ERGSYSBEN Customer Class Energy @ Generation (MWH)	32,312,539	32,248,840	63,699	32,248,840	16,306,911	15,478,831	321,566	-	120,042	21,490
	ERGSYSBEN System Benefits - Energy Related	**100.00%**	**99.80%**	**0.20%**	**99.80%**	**50.47%**	**47.90%**	**1.00%**	**0.00%**	**0.37%**	**0.07%**
	ACC SPECIFIC ALLOCATORS										
27	Retail DEMPROD1 Average & Peak @ Generation (%)	1	1	-	1	1	0	0	0	0	0
	Retail DEMPROD1 Production Demand	**100.00%**	**100.00%**	**-**	**100.00%**	**57.16%**	**41.86%**	**0.75%**	**0.00%**	**0.19%**	**0.03%**
28	Retail DEMTRAN4 4CP @ Generation	7,299,451	7,299,451	-	7,299,451	4,633,776	2,626,742	37,841	-	1,092.00	-
	Retail DEMTRAN4 4CP- Transmission	**100.00%**	**100.00%**	**-**	**100.00%**	**63.48%**	**35.99%**	**0.52%**	**0.00%**	**0.00**	**-**
29	Retail ENERGY1 Customer Class Energy @ Generation (MWH)	32,248,840	32,248,840	-	32,248,840	16,306,911	15,478,831	321,566	-	120,042	21,490
	Retail ENERGY1 Production - Energy	**100.00%**	**100.00%**	**-**	**100.00%**	**50.57%**	**48.00%**	**1.00%**	**0.00%**	**0.37%**	**0.07%**
30	Retail ENERGY2 Customer Class Energy @ Generation including AG-1 (%)	1	1	-	1	1	0	0	-	0	0
	Retail ENERGY2 Production - Energy	**100.00%**	**100.00%**	**-**	**100.00%**	**51.64%**	**46.99%**	**0.98%**	**0.00%**	**0.34%**	**0.06%**
31	Retail ENERGY2_XAG1 Customer Class Energy @ Generation excluding AG-1 (%)	1	1	-	1	1	0	0	-	0	0
	Retail ENERGY2 XAG1 Production - Energy	**100.00%**	**100.00%**	**-**	**100.00%**	**53.33%**	**45.25%**	**1.01%**	**0.00%**	**0.35%**	**0.06%**
32	Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)	32,248,840	32,248,840	-	32,248,840	16,306,911	15,478,831	321,566	-	120,042	21,490
	Retail ERGSYSBEN System Benefits - Energy Related	**100.00%**	**100.00%**	**-**	**100.00%**	**50.57%**	**48.00%**	**1.00%**	**0.00%**	**0.37%**	**0.07%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	ELECTRIC TOTAL	ACC JURISDICTIONAL	ALL OTHER	TOTAL RETAIL	RETAIL					
						RESIDENTIAL	GENERAL SERVICE	E-221 (Non AG)	E-221 (AG)	Street Lighting	Dusk to Dawn
		(A)	(B)	©	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	ACC SPECIFIC ALLOCATORS FOR SOLAR CREDITS										
33	Retail DEMPROD1_XSOL Average & Peak @ Generation (All Other 4CP)	1	1	-	1	1	0	0	0	0	0
	Retail DEMPROD1 XSOL Production Demand (excld Solar)	**100.00%**	**100.00%**	**-**	**100.00%**	**55.39%**	**43.70%**	**0.74%**	**0.00%**	**0.14%**	**0.02%**
34	Retail DEMDIST1_XSOL NCP Demand @ Substation Level w/losses (KW)	7,010,381	7,010,381	-	7,010,381	4,157,805	2,751,764	61,717	-	32,755	6,340
	Retail DEMDIST1 XSOL Distribution Substation (excld Solar)	**100.00%**	**100.00%**	**-**	**100.00%**	**59.31%**	**39.25%**	**0.88%**	**0.00%**	**0.47%**	**0.09%**
35	Retail DEMDIST2_XSOL Demand @ Primary Line Level w/losses (KW)	9,815,070	9,815,070	-	9,815,070	6,766,895	2,947,453	60,051	-	35,200	5,471
	Retail DEMDIST2 XSOL Distribution Primary (excld Solar)	**100.00%**	**100.00%**	**-**	**100.00%**	**68.94%**	**30.03%**	**0.61%**	**0.00%**	**0.36%**	**0.06%**
36	Retail DEMDIST3_XSOL Demand @ Secondary Line Level w/losses (KW)	7,005,000	7,005,000	-	7,005,000	6,967,000	-	-	-	32,000	6,000
	Retail DEMDIST3 XSOL Distribution Secondary (excld Solar)	**100.00%**	**100.00%**	**-**	**100.00%**	**99.46%**	**-**	**-**	**-**	**0.46%**	**0.09%**
37	Retail DEMTRAN4_XSOL 4CP Demand @ Generation	6,615,797	6,615,797	-	6,615,797	3,950,122	2,626,742	37,841	-	1,092	-
	Retail DEMTRAN4 XSOL Transmission (excld Solar)	**100.00%**	**100.00%**	**-**	**100.00%**	**59.71%**	**39.70%**	**0.57%**	**0.00%**	**0.02%**	**-**
38	Retail ENERGY2_XAG1_XSOL Customer Class Energy @ Generation excluding AG-1 MWH	1	1	-	1	0	0	0	0	0	0
	Retail ENERGY2 XAG1 XSOL Production - Energy (excld Solar)	**100.00%**	**100.00%**	**-**	**100.00%**	**49.39%**	**49.07%**	**1.09%**	**0.00%**	**0.38%**	**0.07%**
	REVENUE ALLOCATORS										
39	CUSTADV Customer Advances	$304,363,674	$304,363,674	-	$304,363,674	$59,162,010	$244,625,850	$5,552	-	$570,261	
	CUSTADV Customer Advances	**100.00%**	**100.00%**	**-**	**100.00%**	**19.44%**	**80.37%**	**0.00%**	**0.00%**	**0.19%**	**0.00%**
40	CUSTDEP Customer Deposits	(39,903,153)	(39,903,153)	-	(39,903,153)	(10,927,663)	(28,001,436)	(602,536)	-	(371,517)	-
	CUSTDEP Customer Deposits	**100.00%**	**100.00%**	**-**	**100.00%**	**27.39%**	**70.17%**	**1.51%**	**0.00%**	**0.93%**	**-**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	TOTAL GENERAL SERVICE	GENERAL SERVICE												
			E-20 (Church Rate)	E-32 TOU (0-20kW)	E-32 TOU (21-100kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-20 kW)	E-30, E-32 (21-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35	AG-X
		(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
	CUSTOMER COUNT ALLOCATORS														
1	CUST371 Dusk to Dawn Customer Class Specific (%)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUST371 Dusk to Dawn	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	CUST373 Street Lighting Customer Class Specific (%)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUST373 Street Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	CUST910 Number of Customer Accounts	138,523	378	697	153	93	71	276	112,586	19,116	4,202	802	20	45	84
	CUST910 Customer Service and Information	**10.28%**	**0.03%**	**0.05%**	**0.01%**	**0.01%**	**0.01%**	**0.02%**	**8.36%**	**1.42%**	**0.31%**	**0.06%**	**0.00%**	**0.00%**	**0.01%**
4	CUST916 Number of Customer Accounts	138,523	378	697	153	93	71	276	112,586	19,116	4,202	802	20	45	84
	CUST916 Sales Expense	**10.28%**	**0.03%**	**0.05%**	**0.01%**	**0.01%**	**0.01%**	**0.02%**	**8.36%**	**1.42%**	**0.31%**	**0.06%**	**0.00%**	**0.00%**	**0.01%**
5	CUSTNUM Number of Customer Accounts	138,523	378	697	153	93	71	276	112,586	19,116	4,202	802	20	45	84
	CUSTNUM Customer Accounts	**10.28%**	**0.03%**	**0.05%**	**0.01%**	**0.01%**	**0.01%**	**0.02%**	**8.36%**	**1.42%**	**0.31%**	**0.06%**	**0.00%**	**0.00%**	**0.01%**
6	CUSTNUM_A Number of Customer Accounts ACC	138,523	378	697	153	93	71	276	112,586	19,116	4,202	802	20	45	84
	CUSTNUM A Customer Accounts ACC	**10.28%**	**0.03%**	**0.05%**	**0.01%**	**0.01%**	**0.01%**	**0.02%**	**8.36%**	**1.42%**	**0.31%**	**0.06%**	**0.00%**	**0.00%**	**0.01%**
	CUSTOMER COST ALLOCATORS														
7	CUST370 Costs for Distribution Meters ($)	$47,837,656	$396,950	$119,828	$160,670	$112,231	$203,323	$369,148	$19,355,753	$20,076,426	$4,462,011	$1,777,005	$124,157	$508,620	$171,531
	CUST370 Distribution Meters	**18.76%**	**0.16%**	**0.05%**	**0.06%**	**0.04%**	**0.08%**	**0.14%**	**7.59%**	**7.87%**	**1.75%**	**0.70%**	**0.05%**	**0.20%**	**0.07%**
8	CUSTOH1 Weighted Customer Costs for Distribution Services ($)	$12,229,886	$33,264	$60,984	$13,398	$12,236	-	$35,350	$9,856,770	$1,673,364	$541,121	-	-	-	$3,399
	CUSTOH1 Distribution OH Services	**13.93%**	**0.04%**	**0.07%**	**0.02%**	**0.01%**	**-**	**0.04%**	**11.23%**	**1.91%**	**0.62%**	**-**	**-**	**-**	**0.00%**
9	CUSTUG1 Weighted Customer Costs for Distribution Services ($)	$133,851,785	$335,621	$619,692	$136,003	$168,130	$481,522	$502,148	$100,084,097	$16,993,819	$7,635,347	$5,396,363	$252,859	$568,933	$677,251
	CUSTUG1 Distribution UG Services	**23.30%**	**0.06%**	**0.11%**	**0.02%**	**0.03%**	**0.08%**	**0.09%**	**17.42%**	**2.96%**	**1.33%**	**0.94%**	**0.04%**	**0.10%**	**0.12%**
	DISTRIBUTION DEMAND ALLOCATORS														
10	DEMDIST1 NCP Demand @ Substation Level w/losses (KW)	2,751,764	17,783	4,184	6,277	20,559	51,333	58,579	412,097	610,857	627,886	492,223	91,649	246,134	112,203
	DEMDIST1 Distribution Substation	**35.73%**	**0.23%**	**0.05%**	**0.08%**	**0.27%**	**0.67%**	**0.76%**	**5.35%**	**7.93%**	**8.15%**	**6.39%**	**1.19%**	**3.20%**	**1.46%**
11	DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)	2,677,467	17,303	4,071	6,107	20,004	49,947	56,997	400,971	594,364	610,933	478,933	89,174	239,488	109,175
	DEMDIST2 Distribution OH Primary Lines	**25.80%**	**0.15%**	**0.05%**	**0.05%**	**0.17%**	**0.41%**	**0.47%**	**6.52%**	**5.39%**	**5.09%**	**3.92%**	**0.73%**	**1.95%**	**0.89%**
12	DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DEMDIST3 Distribution OH Secondary Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)	2,677,467	17,303	4,071	6,107	20,004	49,947	56,997	400,971	594,364	610,933	478,933	89,174	239,488	109,175
	DEMDIST4 Distribution UG Primary Lines	**25.80%**	**0.15%**	**0.05%**	**0.05%**	**0.17%**	**0.41%**	**0.47%**	**6.52%**	**5.39%**	**5.09%**	**3.92%**	**0.73%**	**1.95%**	**0.89%**
14	DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DEMDIST5 Distribution UG Secondary Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	2,296,434	22,000	5,983	8,954	24,800	-	80,000	616,834	762,205	775,658	-	-	-	-
	DEMDIST6 Distribution OH Line Transformers	**17.09%**	**0.14%**	**0.05%**	**0.06%**	**0.14%**	**0.00%**	**0.46%**	**6.77%**	**4.90%**	**4.54%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
16	DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	3,257,095	22,000	5,983	8,954	24,800	49,093	80,000	616,834	762,205	775,658	505,801	40,013	89,781	275,973
	DEMDIST7 Distribution UG Line Transformers	**21.04%**	**0.13%**	**0.05%**	**0.05%**	**0.13%**	**0.26%**	**0.43%**	**6.48%**	**4.54%**	**4.18%**	**2.67%**	**0.21%**	**0.47%**	**1.45%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	TOTAL GENERAL SERVICE	GENERAL SERVICE												
			E-20 (Church Rate)	E-32 TOU (0-20kW)	E-32 TOU (21-100kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-20 kW)	E-30, E-32 (21-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35	AG-X
		(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
	PRODUCTION DEMAND ALLOCATORS														
17	DEMPROD1 Average & Peak @ Generation (All Other 4CP) (%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DEMPROD1 Production Demand	**41.81%**	**0.12%**	**0.06%**	**0.08%**	**0.32%**	**0.79%**	**0.54%**	**5.23%**	**8.10%**	**9.35%**	**7.62%**	**1.70%**	**5.25%**	**2.63%**
18	DEMPROD6 Specific Assignment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DEMPROD6 Ancillary Service - Scheduling & Dispatch	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	TRANSMISSION DEMAND ALLOCATORS														
19	DEMTRAN1 Specific Assignment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DEMTRAN1 Transmission Substation	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
20	DEMTRAN3 Specific Assignment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DEMTRAN3 Transmission Lines	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
21	DEMTRAN4 4CP @ Generation (KW)	2,626,742	9,731	3,243	5,405	17,247	46,186	35,679	365,395	568,663	609,547	454,408	94,576	272,714	143,948
	DEMTRAN4 Transmission	**35.94%**	**0.13%**	**0.04%**	**0.07%**	**0.24%**	**0.63%**	**0.49%**	**5.00%**	**7.78%**	**8.34%**	**6.22%**	**1.29%**	**3.73%**	**1.97%**
	ENERGY ALLOCATORS														
22	ENERGY1 Customer Class Energy @ Generation including AG-1 (MWH)	15,478,831	36,409	22,927	30,931	128,494	309,626	194,899	1,763,750	2,725,299	3,361,395	2,933,048	687,479	2,210,279	1,074,295
	ENERGY1 Production - Energy	**47.90%**	**0.11%**	**0.07%**	**0.10%**	**0.40%**	**0.96%**	**0.60%**	**5.46%**	**8.43%**	**10.40%**	**9.08%**	**2.13%**	**6.84%**	**3.32%**
23	ENERGY1_GS General Service Energy @ Generation including AG-1 (MWH)	15,478,831	36,409	22,927	30,931	128,494	309,626	194,899	1,763,750	2,725,299	3,361,395	2,933,048	687,479	2,210,279	1,074,295
	ENERGY1 GS General Service Energy	**100.00%**	**0.24%**	**0.15%**	**0.20%**	**0.83%**	**2.00%**	**1.26%**	**11.39%**	**17.61%**	**21.72%**	**18.95%**	**4.44%**	**14.28%**	**6.94%**
24	ENERGY2 Weighted Hourly Energy Allocator @ Generation including AG-1 (%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ENERGY2 Production - Energy (Fuel and Purchased Power)	**46.90%**	**0.11%**	**0.07%**	**0.09%**	**0.39%**	**0.93%**	**0.60%**	**5.42%**	**8.42%**	**10.25%**	**8.84%**	**2.06%**	**6.54%**	**3.17%**
25	ENERGY2_XAG1 Weighted Hourly Energy Allocator @ Generation excluding AG-1 (%)	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	ENERGY2 XAG1 Production - Energy (Fuel and Purchased Power)	**45.16%**	**0.12%**	**0.07%**	**0.10%**	**0.40%**	**0.96%**	**0.62%**	**5.60%**	**8.70%**	**10.59%**	**9.13%**	**2.13%**	**6.75%**	**-**
26	ERGSYSBEN Customer Class Energy @ Generation (MWH)	15,478,831	36,409	22,927	30,931	128,494	309,626	194,899	1,763,750	2,725,299	3,361,395	2,933,048	687,479	2,210,279	1,074,295
	ERGSYSBEN System Benefits - Energy Related	**47.90%**	**0.11%**	**0.07%**	**0.10%**	**0.40%**	**0.96%**	**0.60%**	**5.46%**	**8.43%**	**10.40%**	**9.08%**	**2.13%**	**6.84%**	**3.32%**
	ACC SPECIFIC ALLOCATORS														
27	Retail DEMPROD1 Average & Peak @ Generation (%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Retail DEMPROD1 Production Demand	**41.86%**	**0.12%**	**0.06%**	**0.08%**	**0.32%**	**0.79%**	**0.55%**	**5.23%**	**8.11%**	**9.36%**	**7.63%**	**1.70%**	**5.26%**	**2.64%**
28	Retail DEMTRAN4 4CP @ Generation	2,626,742	9,731	3,243	5,405	17,247	46,186	35,679	365,395	568,663	609,547	454,408	94,576	272,714	143,948
	Retail DEMTRAN4 4CP- Transmission	**35.99%**	**0.13%**	**0.04%**	**0.07%**	**0.24%**	**0.63%**	**0.49%**	**5.01%**	**7.79%**	**8.35%**	**6.23%**	**1.30%**	**3.74%**	**1.97%**
29	Retail ENERGY1 Customer Class Energy @ Generation (MWH)	15,478,831	36,409	22,927	30,931	128,494	309,626	194,899	1,763,750	2,725,299	3,361,395	2,933,048	687,479	2,210,279	1,074,295
	Retail ENERGY1 Production - Energy	**48.00%**	**0.11%**	**0.07%**	**0.10%**	**0.40%**	**0.96%**	**0.60%**	**5.47%**	**8.45%**	**10.42%**	**9.10%**	**2.13%**	**6.85%**	**3.33%**
30	Retail ENERGY2 Customer Class Energy @ Generation including AG-1 (%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Retail ENERGY2 Production - Energy	**46.99%**	**0.12%**	**0.07%**	**0.09%**	**0.39%**	**0.93%**	**0.60%**	**5.43%**	**8.44%**	**10.27%**	**8.85%**	**2.06%**	**6.55%**	**3.18%**
31	Retail ENERGY2_XAG1 Customer Class Energy @ Generation excluding AG-1 (%)	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Retail ENERGY2 XAG1 Production - Energy	**45.25%**	**0.12%**	**0.07%**	**0.10%**	**0.40%**	**0.96%**	**0.62%**	**5.61%**	**8.71%**	**10.61%**	**9.14%**	**2.13%**	**6.77%**	**-**
32	Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)	15,478,831	36,409	22,927	30,931	128,494	309,626	194,899	1,763,750	2,725,299	3,361,395	2,933,048	687,479	2,210,279	1,074,295
	Retail ERGSYSBEN System Benefits - Energy Related	**48.00%**	**0.11%**	**0.07%**	**0.10%**	**0.40%**	**0.96%**	**0.60%**	**5.47%**	**8.45%**	**10.42%**	**9.10%**	**2.13%**	**6.85%**	**3.33%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	TOTAL GENERAL SERVICE	GENERAL SERVICE												
			E-20 (Church Rate)	E-32 TOU (0-20kW)	E-32 TOU (21-100kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-20 kW)	E-30, E-32 (21-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35	AG-X
		(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
	ACC SPECIFIC ALLOCATORS FOR SOLAR CREDITS														
33	Retail DEMPROD1_XSOL Average & Peak @ Generation (All Other 4CP)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Retail DEMPROD1 XSOL Production Demand (excld Solar)	**43.70%**	**0.14%**	**0.06%**	**0.09%**	**0.32%**	**0.81%**	**0.58%**	**5.65%**	**8.77%**	**9.89%**	**7.84%**	**1.72%**	**5.20%**	**2.64%**
34	Retail DEMDIST1_XSOL NCP Demand @ Substation Level w/losses (KW)	2,751,764	17,783	4,184	6,277	20,559	51,333	58,579	412,097	610,857	627,886	492,223	91,649	246,134	112,203
	Retail DEMDIST1 XSOL Distribution Substation (excld Solar)	**39.25%**	**0.25%**	**0.06%**	**0.09%**	**0.29%**	**0.73%**	**0.84%**	**5.88%**	**8.71%**	**8.96%**	**7.02%**	**1.31%**	**3.51%**	**1.60%**
35	Retail DEMDIST2_XSOL Demand @ Primary Line Level w/losses (KW)	2,947,453	21,881	6,584	6,584	12,448	40,955	40,317	1,047,416	6,584	648,224	571,665	104,301	220,247	220,247
	Retail DEMDIST2 XSOL Distribution Primary (excld Solar)	**30.03%**	**0.22%**	**0.07%**	**0.07%**	**0.13%**	**0.42%**	**0.41%**	**10.67%**	**0.07%**	**6.60%**	**5.82%**	**1.06%**	**2.24%**	**2.24%**
36	Retail DEMDIST3_XSOL Demand @ Secondary Line Level w/losses (KW)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Retail DEMDIST3 XSOL Distribution Secondary (excld Solar)	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
37	Retail DEMTRAN4_XSOL 4CP Demand @ Generation	2,626,742	9,731	3,243	5,405	17,247	46,186	35,679	365,395	568,663	609,547	454,408	94,576	272,714	143,948
	Retail DEMTRAN4 XSOL Transmission (excld Solar)	**39.70%**	**0.15%**	**0.05%**	**0.08%**	**0.26%**	**0.70%**	**0.54%**	**5.52%**	**8.60%**	**9.21%**	**6.87%**	**1.43%**	**4.12%**	**2.18%**
38	Retail ENERGY2_XAG1_XSOL Customer Class Energy @ Generation excluding AG-1 MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Retail ENERGY2 XAG1 XSOL Production - Energy (excld Solar)	**49.07%**	**0.13%**	**0.08%**	**0.11%**	**0.44%**	**1.04%**	**0.67%**	**6.08%**	**9.45%**	**11.51%**	**9.92%**	**2.31%**	**7.34%**	**-**
	REVENUE ALLOCATORS														
39	CUSTADV Customer Advances	$244,625,850	$504,574	$379,770	$502,857	$1,330,941	$3,437,255	$2,420,338	$31,868,770	$40,762,050	$43,984,495	$33,043,184	$4,876,506	$71,236,405	$10,278,705
	CUSTADV Customer Advances	**80.37%**	**0.17%**	**0.12%**	**0.17%**	**0.44%**	**1.13%**	**0.80%**	**10.47%**	**13.39%**	**14.45%**	**10.86%**	**1.60%**	**23.41%**	**3.38%**
40	CUSTDEP Customer Deposits	(28,001,436)	(73,202)	(55,096)	(72,953)	(193,089)	(498,667)	(351,136)	(4,623,428)	(5,913,640)	(6,381,143)	(4,793,809)	(707,469)	(2,846,600)	(1,491,205)
	CUSTDEP Customer Deposits	**70.17%**	**0.18%**	**0.14%**	**0.18%**	**0.48%**	**1.25%**	**0.88%**	**11.59%**	**14.82%**	**15.99%**	**12.01%**	**1.77%**	**7.13%**	**3.74%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	TOTAL RES DENTIAL	RESIDENTIAL								
			Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)	R-Basic (0-600kW)	R-Basic (601-999kW)	R-Basic (1000+kW)	R-TOU	R-Demand
		(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)
	CUSTOMER COUNT ALLOCATORS										
1	CUST371 Dusk to Dawn Customer Class Specific (%)	-	-	-	-	-	-	-	-	-	-
	CUST371 Dusk to Dawn	-	-	-	-	-	-	-	-	-	-
2	CUST373 Street Lighting Customer Class Specific (%)	-	-	-	-	-	-	-	-	-	-
	CUST373 Street Lighting	-	-	-	-	-	-	-	-	-	-
3	CUST910 Number of Customer Accounts	1,197,816	73,106	1,525	47,698	15,571	326,700	84,099	21,665	292,758	334,694
	CUST910 Customer Service and Information	**88.91%**	**5.43%**	**0.11%**	**3.54%**	**1.16%**	**24.25%**	**6.24%**	**1.61%**	**21.73%**	**24.84%**
4	CUST916 Number of Customer Accounts	1,197,816	73,106	1,525	47,698	15,571	326,700	84,099	21,665	292,758	334,694
	CUST916 Sales Expense	**88.91%**	**5.43%**	**0.11%**	**3.54%**	**1.16%**	**24.25%**	**6.24%**	**1.61%**	**21.73%**	**24.84%**
5	CUSTNUM Number of Customer Accounts	1,197,816	73,106	1,525	47,698	15,571	326,700	84,099	21,665	292,758	334,694
	CUSTNUM Customer Accounts	**88.91%**	**5.43%**	**0.11%**	**3.54%**	**1.16%**	**24.25%**	**6.24%**	**1.61%**	**21.73%**	**24.84%**
6	CUSTNUM_A Number of Customer Accounts ACC	1,197,816	73,106	1,525	47,698	15,571	326,700	84,099	21,665	292,758	334,694
	CUSTNUM A Customer Accounts ACC	**88.91%**	**5.43%**	**0.11%**	**3.54%**	**1.16%**	**24.25%**	**6.24%**	**1.61%**	**21.73%**	**24.84%**
	CUSTOMER COST ALLOCATORS										
7	CUST370 Costs for Distribution Meters ($)	$205,812,998	$12,507,023	$260,898	$8,160,206	$2,663,897	$56,166,171	$14,458,276	$3,725,156	$50,330,872	$57,540,498
	CUST370 Distribution Meters	**80.70%**	**4.90%**	**0.10%**	**3.20%**	**1.04%**	**22.02%**	**5.67%**	**1.46%**	**19.74%**	**22.56%**
8	CUSTOH1 Weighted Customer Costs for Distribution Services ($)	$75,377,592	$4,600,501	$95,967	$3,001,597	$979,870	$20,558,967	$5,292,282	$1,363,361	$18,423,024	$21,062,023
	CUSTOH1 Distribution OH Services	**85.88%**	**5.24%**	**0.11%**	**3.42%**	**1.12%**	**23.42%**	**6.03%**	**1.55%**	**20.99%**	**24.00%**
9	CUSTUG1 Weighted Customer Costs for Distribution Services ($)	$438,358,760	$26,754,239	$558,097	$17,455,800	$5,698,441	$119,560,773	$30,777,292	$7,928,632	$107,139,188	$122,486,297
	CUSTUG1 Distribution UG Services	**76.31%**	**4.66%**	**0.10%**	**3.04%**	**0.99%**	**20.81%**	**5.36%**	**1.38%**	**18.65%**	**21.32%**
	DISTRIBUTION DEMAND ALLOCATORS										
10	DEMDIST1 NCP Demand @ Substation Level w/losses (KW)	4,849,893	422,649	11,623	178,569	79,247	582,198	293,741	109,889	1,345,079	1,826,898
	DEMDIST1 Distribution Substation	**62.97%**	**5.49%**	**0.15%**	**2.32%**	**1.03%**	**7.56%**	**3.81%**	**1.43%**	**17.46%**	**23.72%**
11	DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)	4,718,946	411,237	11,309	173,748	77,107	566,479	285,810	106,922	1,308,762	1,777,572
	DEMDIST2 Distribution OH Primary Lines	**73.08%**	**5.46%**	**0.14%**	**2.79%**	**1.08%**	**14.07%**	**4.76%**	**1.50%**	**19.13%**	**24.16%**
12	DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	8,180,000	632,000	17,000	414,000	150,000	1,326,000	498,000	179,000	2,189,000	2,775,000
	DEMDIST3 Distribution OH Secondary Lines	**99.54%**	**7.69%**	**0.21%**	**5.04%**	**1.83%**	**16.14%**	**6.06%**	**2.18%**	**26.64%**	**33.77%**
13	DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)	4,718,946	411,237	11,309	173,748	77,107	566,479	285,810	106,922	1,308,762	1,777,572
	DEMDIST4 Distribution UG Primary Lines	**73.08%**	**5.46%**	**0.14%**	**2.79%**	**1.08%**	**14.07%**	**4.76%**	**1.50%**	**19.13%**	**24.16%**
14	DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	8,180,000	632,000	17,000	414,000	150,000	1,326,000	498,000	179,000	2,189,000	2,775,000
	DEMDIST5 Distribution UG Secondary Lines	**99.54%**	**7.69%**	**0.21%**	**5.04%**	**1.83%**	**16.14%**	**6.06%**	**2.18%**	**26.64%**	**33.77%**
15	DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	8,262,626	638,384	17,172	418,182	151,515	1,339,394	503,030	180,808	2,211,111	2,803,030
	DEMDIST6 Distribution OH Line Transformers	**81.75%**	**5.75%**	**0.14%**	**3.76%**	**1.31%**	**17.09%**	**5.30%**	**1.66%**	**21.07%**	**25.66%**
16	DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	8,262,626	638,384	17,172	418,182	151,515	1,339,394	503,030	180,808	2,211,111	2,803,030
	DEMDIST7 Distribution UG Line Transformers	**77.87%**	**5.45%**	**0.13%**	**3.57%**	**1.24%**	**16.46%**	**5.06%**	**1.57%**	**20.03%**	**24.34%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	TOTAL RES DENTIAL	RESIDENTIAL								
			Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)	R-Basic (0-600kW)	R-Basic (601-999kW)	R-Basic (1000+kW)	R-TOU	R-Demand
		(Y)	*(Z)*	*(AA)*	*(AB)*	*(AC)*	*(AD)*	*(AE)*	*(AF)*	*(AG)*	*(AH)*
	PRODUCTION DEMAND ALLOCATORS										
17	DEMPROD1 Average & Peak @ Generation (All Other 4CP) (%)	1	0	0	0	0	0	0	0	0	0
	DEMPROD1 Production Demand	**57.10%**	**4.94%**	**0.14%**	**2.30%**	**0.98%**	**7.38%**	**3.36%**	**1.34%**	**15.18%**	**21.48%**
18	DEMPROD6 Specific Assignment	-	-	-	-	-	-	-	-	-	-
	DEMPROD6 Ancillary Service - Scheduling & Dispatch	-	-	-	-	-	-	-	-	-	-
	TRANSMISSION DEMAND ALLOCATORS										
19	DEMTRAN1 Specific Assignment	-	-	-	-	-	-	-	-	-	-
	DEMTRAN1 Transmission Substation	-	-	-	-	-	-	-	-	-	-
20	DEMTRAN3 Specific Assignment	-	-	-	-	-	-	-	-	-	-
	DEMTRAN3 Transmission Lines	-	-	-	-	-	-	-	-	-	-
21	DEMTRAN4 4CP @ Generation (KW)	4,633,776	409,537	10,921	186,749	76,447	589,733	287,222	108,118	1,252,638	1,712,411
	DEMTRAN4 Transmission	**63.41%**	**5.60%**	**0.15%**	**2.56%**	**1.05%**	**8.07%**	**3.93%**	**1.48%**	**17.14%**	**23.43%**
	ENERGY ALLOCATORS										
22	ENERGY1 Customer Class Energy @ Generation including AG-1 (MWH)	16,306,911	1,369,900	41,695	653,276	296,292	2,153,372	893,088	383,785	4,240,271	6,275,232
	ENERGY1 Production - Energy	**50.47%**	**4.24%**	**0.13%**	**2.02%**	**0.92%**	**6.66%**	**2.76%**	**1.19%**	**13.12%**	**19.42%**
23	ENERGY1_GS General Service Energy @ Generation including AG-1 (MWH)	-	-	-	-	-	-	-	-	-	-
	ENERGY1 GS General Service Energy	-	-	-	-	-	-	-	-	-	-
24	ENERGY2 Weighted Hourly Energy Allocator @ Generation including AG-1 (%)	1	0	0	0	0	0	0	0	0	0
	ENERGY2 Production - Energy (Fuel and Purchased Power)	**51.53%**	**4.35%**	**0.13%**	**2.10%**	**0.94%**	**6.75%**	**2.84%**	**1.21%**	**13.42%**	**19.79%**
25	ENERGY2_XAG1 Weighted Hourly Energy Allocator @ Generation excluding AG-1 (%)	1	0	0	0	0	0	0	0	0	0
	ENERGY2 XAG1 Production - Energy (Fuel and Purchased Power)	**53.22%**	**4.49%**	**0.14%**	**2.17%**	**0.97%**	**6.97%**	**2.93%**	**1.25%**	**13.86%**	**20.44%**
26	ERGSYSBEN Customer Class Energy @ Generation (MWH)	16,306,911	1,369,900	41,695	653,276	296,292	2,153,372	893,088	383,785	4,240,271	6,275,232
	ERGSYSBEN System Benefits - Energy Related	**50.47%**	**4.24%**	**0.13%**	**2.02%**	**0.92%**	**6.66%**	**2.76%**	**1.19%**	**13.12%**	**19.42%**
	ACC SPECIFIC ALLOCATORS										
27	Retail DEMPROD1 Average & Peak @ Generation (%)	1	0	0	0	0	0	0	0	0	0
	Retail DEMPROD1 Production Demand	**57.16%**	**4.94%**	**0.14%**	**2.30%**	**0.98%**	**7.39%**	**3.36%**	**1.34%**	**15.20%**	**21.50%**
28	Retail DEMTRAN4 4CP @ Generation	4,633,776	409,537	10,921	186,749	76,447	589,733	287,222	108,118	1,252,638	1,712,411
	Retail DEMTRAN4 4CP- Transmission	**63.48%**	**5.61%**	**0.15%**	**2.56%**	**1.05%**	**8.08%**	**3.93%**	**1.48%**	**17.16%**	**23.46%**
29	Retail ENERGY1 Customer Class Energy @ Generation (MWH)	16,306,911	1,369,900	41,695	653,276	296,292	2,153,372	893,088	383,785	4,240,271	6,275,232
	Retail ENERGY1 Production - Energy	**50.57%**	**4.25%**	**0.13%**	**2.03%**	**0.92%**	**6.68%**	**2.77%**	**1.19%**	**13.15%**	**19.46%**
30	Retail ENERGY2 Customer Class Energy @ Generation including AG-1 (%)	1	0	0	0	0	0	0	0	0	0
	Retail ENERGY2 Production - Energy	**51.64%**	**4.36%**	**0.13%**	**2.11%**	**0.94%**	**6.76%**	**2.85%**	**1.21%**	**13.45%**	**19.83%**
31	Retail ENERGY2_XAG1 Customer Class Energy @ Generation excluding AG-1 (%)	1	0	0	0	0	0	0	0	0	0
	Retail ENERGY2 XAG1 Production - Energy	**53.33%**	**4.50%**	**0.14%**	**2.18%**	**0.97%**	**6.98%**	**2.94%**	**1.25%**	**13.89%**	**20.48%**
32	Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)	16,306,911	1,369,900	41,695	653,276	296,292	2,153,372	893,088	383,785	4,240,271	6,275,232
	Retail ERGSYSBEN System Benefits - Energy Related	**50.57%**	**4.25%**	**0.13%**	**2.03%**	**0.92%**	**6.68%**	**2.77%**	**1.19%**	**13.15%**	**19.46%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE G-7
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2022

Line No.	ALLOCATION FACTORS	TOTAL RES DENTIAL	RESIDENTIAL								
			Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)	R-Basic (0-600kW)	R-Basic (601-999kW)	R-Basic (1000+kW)	R-TOU	R-Demand
		(Y)	*(Z)*	*(AA)*	*(AB)*	*(AC)*	*(AD)*	*(AE)*	*(AF)*	*(AG)*	*(AH)*
	ACC SPECIFIC ALLOCATORS FOR SOLAR CREDITS										
33	Retail DEMPROD1_XSOL Average & Peak @ Generation (All Other 4CP)	1	-	-	-	-	0	0	0	0	0
	Retail DEMPROD1 XSOL Production Demand (excld Solar)	**55.39%**	**-**	**-**	**-**	**-**	**8.35%**	**3.89%**	**1.52%**	**17.36%**	**24.27%**
34	Retail DEMDIST1_XSOL NCP Demand @ Substation Level w/losses (KW)	4,157,805	-	-	-	-	582,198	293,741	109,889	1,345,079	1,826,898
	Retail DEMDIST1 XSOL Distribution Substation (excld Solar)	**59.31%**	**-**	**-**	**-**	**-**	**8.30%**	**4.19%**	**1.57%**	**19.19%**	**26.06%**
35	Retail DEMDIST2_XSOL Demand @ Primary Line Level w/losses (KW)	6,766,895	-	-	-	-	1,186,258	1,186,258	1,186,258	2,281,576	926,545
	Retail DEMDIST2 XSOL Distribution Primary (excld Solar)	**68.94%**	**-**	**-**	**-**	**-**	**12.09%**	**12.09%**	**12.09%**	**23.25%**	**9.44%**
36	Retail DEMDIST3_XSOL Demand @ Secondary Line Level w/losses (KW)	6,967,000	-	-	-	-	1,326,000	498,000	179,000	2,189,000	2,775,000
	Retail DEMDIST3 XSOL Distribution Secondary (excld Solar)	**99.46%**	**-**	**-**	**-**	**-**	**18.93%**	**7.11%**	**2.56%**	**31.25%**	**39.61%**
37	Retail DEMTRAN4_XSOL 4CP Demand @ Generation	3,950,122	-	-	-	-	589,733	287,222	108,118	1,252,638	1,712,411
	Retail DEMTRAN4 XSOL Transmission (excld Solar)	**59.71%**	**-**	**-**	**-**	**-**	**8.91%**	**4.34%**	**1.63%**	**18.93%**	**25.88%**
38	Retail ENERGY2_XAG1_XSOL Customer Class Energy @ Generation excluding AG-1 MWH	0	-	-	-	-	0	0	0	0	0
	Retail ENERGY2 XAG1 XSOL Production - Energy (excld Solar)	**49.39%**	**-**	**-**	**-**	**-**	**7.57%**	**3.19%**	**1.36%**	**15.06%**	**22.21%**
	REVENUE ALLOCATORS										
39	CUSTADV Customer Advances	$59,162,010	$1,897,311	$99,634	$1,848,835	$795,066	$8,792,151	$3,722,440	$1,684,270	$17,663,583	$22,658,719
	CUSTADV Customer Advances	**19.44%**	**0.62%**	**0.03%**	**0.61%**	**0.26%**	**2.89%**	**1.22%**	**0.55%**	**5.80%**	**7.44%**
40	CUSTDEP Customer Deposits	(10,927,663)	(350,448)	(18,403)	(341,494)	(146,855)	(1,623,976)	(687,562)	(311,097)	(3,262,595)	(4,185,234)
	CUSTDEP Customer Deposits	**27.39%**	**0.88%**	**0.05%**	**0.86%**	**0.37%**	**4.07%**	**1.72%**	**0.78%**	**8.18%**	**10.49%**

Supporting Schedules:
N/A

Recap Schedules:
G-3
G-4

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-1
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
ADJUSTED TEST YEAR ENDING JUNE 30, 2022

		Base Revenues in the Test Year (a)		Proposed Increase (d)		Adjustor Impacts (d)			Day One Impacts (d)			
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
Line No.	Customer Classification	Present Rates (b) [1, 2] ($000)	Proposed Rates (c) [2] ($000)	Change ($000) (B) - (A)	% (C) / (A)	Adjustor Transfers [3] ($000)	Net Change ($000) (C) - (E)	Net Increase [4] % (F) / (A)	Day One Impact Adjustments [5] ($000)	Day One Change ($000) (F) - (H)	Day One Net Increase [6] % (I) / (A)	Line No.
1.	Residential	$ 1,819,311	$ 2,234,013	$ 414,702	22.79%	$ 67,264	$ 347,438	19.10%	$ 99,641	$ 247,797	13.62%	1.
2.	General Service	1,499,081	1,843,319	344,238	22.96%	38,511	305,727	20.39%	101,540	204,187	13.62%	2.
3.	Irrigation/Water Pumping	30,336	38,706	8,370	27.59%	1,832	6,538	21.55%	2,406	4,132	13.62%	3.
4.	Outdoor Lighting	19,297	22,896	3,599	18.65%	185	3,414	17.69%	785	2,629	13.62%	4.
5.	Dusk to Dawn Lighting Service	8,787	10,150	1,363	15.51%	34	1,329	15.12%	132	1,197	13.62%	5.
6.	Total Sales to Ultimate Retail Customers	$ 3,376,812	$ 4,149,084	$ 772,272	22.87%	$ 107,826	$ 664,446	19.68%	$ 204,504	$ 459,942	13.62%	6.

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments
2) Present and Proposed Rates base revenues include transmission costs based on OATT rates effective during Test Year
3) Test Year adjustor revenue, less E-36 revenue credits, transferred to base rates.
4) Average base bill impact net of adjustor transfers prior to Day One adjustments
5) Includes adjustor revenue changes occurring on Day One of new rates.
6) Increase in base rates net of transfers and Day One adjustor revenue which represents the final net increase in retail revenue and Day One net impact on customers

Supporting Schedules:
(a) H-2
(b) G-1
(c) G-2

Recap Schedules:
(d) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-2
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
ADJUSTED TEST YEAR ENDING JUNE 30, 2022

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
							Proposed Revenue							
Line No.	Customer Classification and Current Rate Designation	Average Number of Customers	Adjusted MWh [2] Sales	Average Annual kWh Usage per Customer	Base Revenues under Present Rates [1] ($000)	Proposed Rate Designation	Base Revenues ($000)	Change - Base Rates ($000)	%	Net Increase With Adjustor Transfers ($000)	%	Adjustor ($000)	Day 1 Impact ($000)	Line No.
								(G) - (E)	(H) / (E)		(J) / (E)			
1	Residential													1
2	R-1 Small	321,356	2,185,208	6,800	$ 279,634	R-1 Small	$ 343,382	$ 63,748	22.80%	$ 54,538	19.50%	$ 9,210	$ 14,675	2
3	R-1 Medium	83,917	834,563	9,945	111,210	R-1 Medium	136,563	25,353	22.80%	21,435	19.27%	3,918	5,770	3
4	R-1 Large	19,657	381,627	19,414	53,503	R-1 Large	65,699	12,196	22.79%	10,555	19.73%	1,641	2,693	4
5	TOU-E	338,868	4,383,749	12,936	582,846	TOU-E	715,702	132,856	22.79%	112,239	19.26%	20,617	30,568	5
6	R-2	96,121	1,360,775	14,157	169,895	R-2	208,613	38,718	22.79%	31,328	18.44%	7,390	9,465	6
7	R-3	255,514	4,987,507	19,520	561,095	R-3	688,991	127,896	22.79%	105,875	18.87%	22,021	33,874	7
8	R-TECH	52	927	17,827	118	R-TECH	145	27	22.88%	23	19.49%	4	7	8
9	Subtotal	1,115,485	14,134,356	12,671	$ 1,758,301	Subtotal	$ 2,159,095	$ 400,794	22.79%	$ 335,993	19.11%	$ 64,801	$ 97,051	9
10	E-12 Solar Legacy	29,746	106,168	3,569	$ 17,125	E-12 Solar Legacy	$ 21,028	$ 3,903	22.79%	$ 3,372	19.69%	$ 531	$ 513	10
11	ET-1 Solar Legacy	9,537	68,956	7,230	8,217	ET-1 Solar Legacy	10,090	1,873	22.79%	1,519	18.49%	354	378	11
12	ET-2 Solar Legacy	34,065	280,188	8,225	32,654	ET-2 Solar Legacy	40,098	7,444	22.80%	6,001	18.38%	1,443	1,559	12
13	ECT-1R Solar Legacy	210	3,297	15,700	466	ECT-1R Solar Legacy	573	107	22.96%	(7)	-1.50%	114	118	13
14	ECT-2 Solar Legacy	1,311	18,205	13,886	2,548	ECT-2 Solar Legacy	3,129	581	22.80%	560	21.98%	21	22	14
15	Subtotal	74,869	476,814	6,369	$ 61,010	Subtotal	$ 74,918	$ 13,908	22.80%	$ 11,445	18.76%	$ 2,463	$ 2,590	15
16	Total Residential	1,190,354	14,611,170	12,275	$ 1,819,311	Total Residential	$ 2,234,013	$ 414,702	22.79%	$ 347,438	19.10%	$ 67,264	$ 99,641	16

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-2
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
ADJUSTED TEST YEAR ENDING JUNE 30, 2022

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
							Proposed Revenue							
Line No.	Customer Classification and Current Rate Designation	Average Number of Customers	Adjusted MWh [2] Sales	Average Annual kWh Usage per Customer	Base Revenues under Present Rates[1] ($000)	Proposed Rate Designation	Base Revenues ($000)	Change - Base Rates ($000) (G) - (E)	Change - Base Rates % (H) / (E)	Net Increase With Adjustor Transfers ($000)	% (J) / (E)	Adjustor ($000)	Day 1 Impact ($000)	Line No.
17	General Service													17
18	E-20	377	31,657	83,971	$ 3,907	E-20	$ 4,835	$ 928	23.75%	$ 723	18.51%	$ 205	$ 188	18
19	E-30	4,256	4,619	1,085	1,189	E-30	1,472	283	23.80%	275	23.13%	8	32	19
20	E-32 XS	106,450	1,677,274	15,756	240,232	E-32 XS	297,288	57,056	23.75%	50,556	21.04%	6,500	10,258	20
21	E-32 XS D	1,412	43,577	30,862	5,300	E-32 XS D	6,559	1,259	23.75%	1,156	21.81%	103	283	21
22	E-32 S	18,977	2,605,782	137,313	316,135	E-32 S	391,224	75,089	23.75%	64,924	20.54%	10,165	16,992	22
23	E-32 M	4,182	3,339,249	798,481	340,104	E-32 M (includes AG-X)	426,521	81,367	23.57%	70,326	20.38%	11,041	24,013	23
24	E-32 M (AG-X)	29	47,394	1,634,276	5,050									24
25	E-32 L	784	2,942,724	3,753,474	259,507	E-32 L (includes AG-X)	357,262	64,777	22.15%	59,800	20.45%	4,977	22,165	25
26	E-32 L (AG-X)	62	272,122	4,389,065	32,978									26
27	E-32TOU XS	669	22,715	33,954	3,043	E-32TOU XS	3,766	723	23.76%	666	21.89%	57	143	27
28	E-32TOU S	154	30,376	197,247	3,696	E-32TOU S	4,574	878	23.76%	780	21.10%	98	216	28
29	E-32TOU M	94	99,305	1,056,436	9,916	E-32TOU M	12,274	2,358	23.78%	2,050	20.67%	308	747	29
30	E-32TOU L	64	337,180	5,268,438	29,476	E-32TOU L (includes AG-X)	36,516	7,018	23.79%	6,548	22.20%	470	2,321	30
31	E-32 TOU L (AG-X)	1	253	253,000	22									31
32	E-34	19	636,563	33,503,316	40,464	(E-34, E-35, XHLF, AG-X)	277,752	47,971	20.88%	44,375	19.31%	3,596	23,122	32
33	E-34 (AG-X)	2	45,561	22,780,500	4,919									33
34	E-35	35	1,329,354	37,981,543	98,895									34
35	E-35 (AG-X)	4	501,417	125,354,250	36,318									35
36	XHLF	8	837,159	104,644,875	49,185									36
37	GS-S M	220	113,267	514,850	13,454	GS-S M	16,717	3,263	24.25%	2,573	19.12%	690	732	37
38	GS-S L	41	50,473	1,231,049	5,291	GS-S L	6,559	1,268	23.97%	975	18.43%	293	328	38
39	Subtotal	137,840	14,968,021	108,590	$ 1,499,081	Subtotal	$ 1,843,319	$ 344,238	22.96%	$ 305,727	20.39%	$ 38,511	$ 101,540	39

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-2
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
ADJUSTED TEST YEAR ENDING JUNE 30, 2022

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
							Proposed Revenue							
Line No.	Customer Classification and Current Rate Designation	Average Number of Customers	Adjusted MWh [2] Sales	Average Annual kWh Usage per Customer	Base Revenues under Present Rates[1] ($000)	Proposed Rate Designation	Base Revenues ($000)	Change - Base Rates ($000) (G) - (E)	Change - Base Rates % (H) / (E)	Net Increase With Adjustor Transfers ($000)	% (J) / (E)	Adjustor ($000)	Day 1 Impact ($000)	Line No.
40	Irrigation	1,256	322,071	256,426	$ 30,336	Irrigation	$ 38,706	$ 8,370	27.59%	$ 6,538	21.55%	$ 1,832	$ 2,406	40
41	Outdoor Lighting													41
42	E-58	803	23,605	29,396	$ 8,752	E-58	$ 10,384	$ 1,632	18.65%	$ 1,592	18.19%	$ 40	$ 158	42
43	E-59	415	64,657	155,800	8,944	E-59	10,612	1,668	18.65%	1,557	17.41%	111	486	43
44	E-67	149	5,709	38,315	310	E-67	368	58	18.71%	48	15.48%	10	40	44
45	Contract 12	43	13,878	322,744	1,291	Contract 12	1,532	241	18.67%	217	16.81%	24	101	45
46	Subtotal	1,410	107,849	76,489	$ 19,297	Subtotal	$ 22,896	$ 3,599	18.65%	$ 3,414	17.69%	$ 185	$ 785	46
47	Dusk to Dawn Lighting[3]		19,749		$ 8,787	Dusk to Dawn Lighting[3]	$ 10,150	$ 1,363	15.51%	$ 1,329	15.12%	$ 34	$ 132	47
48	Total Retail	1,330,860	30,028,860	22,564	$ 3,376,812		$ 4,149,084	$ 772,272	22.87%	$ 664,446	19.68%	$ 107,826	$ 204,504	48

1. Base Revenues under Present Rates reflect adjusted test year revenues based on rates established in Decision No. 78317.
2. MWh and sales excludes revenue credits. With revenue credits = 30,146,845 MWh.
3. Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.

Additional Notes
Rider rate schedules are included in the "Parent" rate schedules listed on SFR Schedule H-2 as applicable.
Riders include: E-3, E-4, CPP-RES, PPR, CPP-GS, GPS-1, GPS-2, GPS-3, E-56, E-56 R and SGSP.
Rate Schedule E-36 is not included as proposed price changes are market-related.
Transmission revenues are based on OATT charges effective during Test Year.

Supporting Schedules:
N/A

Recap Schedules:
(a) H-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1	E-3	Residential Energy	Rate	Sum & Win	Discount	25%	per bill	Discount: 0%-75% of Federal Poverty level	60%	per bill	35%	1
2		Support Program						Cap: 0%-75% of Federal Poverty level	$ 165.00	per bill		2
3								Discount: >75%-200% of Federal Poverty level	25%	per bill	-	3
4								Cap: >75%-200% of Federal Poverty level	$ 95.00	per bill		4
5												5
6	E-4	Medical Care	Rate	Sum & Win	Discount	35%	per bill	Discount: 0%-75% of Federal Poverty level	60%	per bill	25%	6
7		Equipment						Cap: 0%-75% of Federal Poverty level	$ 165.00	per bill		7
8		Support Program						Discount: >75%-200% of Federal Poverty level	35%	per bill	-	8
9								Cap: >75%-200% of Federal Poverty level	$ 95.00	per bill		9
10												10
11	E-3 Legacy	Residential Energy	Rate	Sum & Win	0 kWh to 400 kWh	65%	per bill	0 kWh to 400 kWh	65%	per bill	-	11
12		Support Program			401 kWh to 800 kWh	45%	per bill	401 kWh to 800 kWh	45%	per bill	-	12
13					801 kWh to 1,200 kWh	26%	per bill	801 kWh to 1,200 kWh	26%	per bill	-	13
14					1,201 kWh and above	$ 31.75	per bill	1,201 kWh and above	$ 31.75	per bill	-	14
15												15
16	E-4 Legacy	Medical Care	Rate	Sum & Win	0 kWh to 800 kWh	65%	per bill	0 kWh to 800 kWh	65%	per bill	-	16
17		Equipment			801 kWh to 1,400 kWh	45%	per bill	801 kWh to 1,400 kWh	45%	per bill	-	17
18		Support Program			1,401 kWh to 2,000 kWh	26%	per bill	1,401 kWh to 2,000 kWh	26%	per bill	-	18
19					2,001 kWh and above	$ 60.00	per bill	2,001 kWh and above	$ 60.00	per bill	-	19
20												20
21	R1 -S	Residential Service	Rate	Summer	Basic Service Charge	$ 0.316	/day	Basic Service Charge	$ 0.393	/day	$ 0.077	21
22		Annual monthly usage less than			All kWh	0.11298	/kWh	All kWh	0.13847	/kWh	0.02549	22
23		or equal to 600 kWh		Winter								23
24					Basic Service Charge	0.316	/day	Basic Service Charge	0.393	/day	0.07700	24
25					All kWh	0.11298	/kWh	All kWh	0.13847	/kWh	0.02549	25
26												26
27												27
28	R1 - M	Residential Service	Rate	Summer	Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	28
29		Annual monthly usage of more			All kWh	0.12282	/kWh	All kWh	0.15053	/kWh	0.02771	29
30		than 600 but less than 1,000 kwh		Winter								30
31					Basic Service Charge	0.400	/day	Basic Service Charge	0.500	/day	0.10000	31
32					All kWh	0.12282	/kWh	All kWh	0.15053	/kWh	0.02771	32
33												33
34												34
35	R1 - L	Residential Service	Rate	Summer	Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	35
36		Annual monthly usage of 1000			All kWh	0.13478	/kWh	All kWh	0.16533	/kWh	0.03055	36
37		or more		Winter								37
38					Basic Service Charge	0.400	/day	Basic Service Charge	0.500	/day	0.10000	38
39					All kWh	0.13478	/kWh	All kWh	0.16533	/kWh	0.03055	39
40												40
41												41
42	RTOU-E	Residential Service	Rate	Summer	Basic Service Charge	$ 0.400	/day	Basic Service Charge	N/A	/day	N/A	42
43	Time-of-Use	Time of Use			All On-Peak kWh	0.23593	/kWh	All On-Peak kWh	N/A	/kWh	N/A	43
44	3pm-8pm Weekdays				All Off-Peak kWh	0.10532	/kWh	All Off-Peak kWh	N/A	/kWh	N/A	44
45												45
46				Winter								46
47					Basic Service Charge	$ 0.400	/day	Basic Service Charge	N/A	/day	N/A	47
48					All On-Peak kWh	0.22386	/kWh	All On-Peak kWh	N/A	/kWh	N/A	48
49					All Off-Peak kWh	0.10533	/kWh	All Off-Peak kWh	N/A	/kWh	N/A	49
50					All Super Off-Peak kWh	0.03166	/kWh	All Super Off-Peak kWh	N/A	/kWh	N/A	50
51												51
52				Sum & Win	All kW-dc of generation (Grid Access Charge)	$ -	/kW-dc	All kW-dc of generation (Grid Access Charge)	N/A	/kW-dc	N/A	52
53												53

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
54	RTOU-E	Residential Service	Rate	Summer	Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	54
55	Time-of-Use	Time of Use			All On-Peak kWh	0.29780	/kWh	All On-Peak kWh	0.36935	/kWh	0.07155	55
56	4pm-7pm Weekdays				All Off-Peak kWh	0.10789	/kWh	All Off-Peak kWh	0.13202	/kWh	0.02413	56
57												57
58				Winter								58
59					Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	59
60					All On-Peak kWh	0.28185	/kWh	All On-Peak kWh	0.34944	/kWh	0.06759	60
61					All Off-Peak kWh	0.10790	/kWh	All Off-Peak kWh	0.13203	/kWh	0.02413	61
62					All Super Off-Peak kWh	0.03166	/kWh	All Super Off-Peak kWh	0.03676	/kWh	0.00510	62
63												63
64				Sum & Win	All kW-dc of generation (Grid Access Charge)	$ -	/kW-dc	All kW-dc of generation (Grid Access Charge)	$ -	/kW-dc	-	64
65												65
66	R-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.409	/day	Basic Service Charge	$ 0.512	/day	$ 0.103	66
67	Saver Choice Plus	Time of Use with			All On-Peak kW	8.084	/kW	All On-Peak kW	10.116	/kW	2.03200	67
68		Demand Charge			All On-Peak kWh	0.12709	/kWh	All On-Peak kWh	0.15623	/kWh	0.02914	68
69					All Off-Peak kWh	0.07575	/kWh	All Off-Peak kWh	0.09197	/kWh	0.01622	69
70				Winter								70
71					Basic Service Charge	$ 0.409	/day	Basic Service Charge	$ 0.512	/day	$ 0.103	71
72					All On-Peak kW	8.084	/kW	All On-Peak kW	10.116	/kW	2.032	72
73					All On-Peak kWh	0.10648	/kWh	All On-Peak kWh	0.13042	/kWh	0.02394	73
74					All Off-Peak kWh	0.07566	/kWh	Off-Peak kWh	0.09184	/kWh	0.01618	74
75					All Super Off-Peak kWh	0.07566	/kWh	All Super Off-Peak kWh	0.09184	/kWh	0.01618	75
76												76
77	R-3	Residential Service	Rate	Summer	Basic Service Charge	$ 0.400	/day	Basic Service Charge	N/A	/day	N/A	77
78	Time-of-Use 3pm-8pm	Time of Use with			All On-Peak kW	16.870	/kW	All On-Peak kW	N/A	/kW	N/A	78
79	Weekdays with Demand	Demand Charge			All On-Peak kWh	0.08615	/kWh	All On-Peak kWh	N/A	/kWh	N/A	79
80					All Off-Peak kWh	0.05146	/kWh	All Off-Peak kWh	N/A	/kWh	N/A	80
81				Winter								81
82					Basic Service Charge	$ 0.400	/day	Basic Service Charge	N/A	/day	N/A	82
83					All On-Peak kW	11.842	/kW	All On-Peak kW	N/A	/kW	N/A	83
84					All On-Peak kWh	0.06323	/kWh	All On-Peak kWh	N/A	/kWh	N/A	84
85					All Off-Peak kWh	0.05137	/kWh	Off-Peak kWh	N/A	/kWh	N/A	85
86					All Super Off-Peak kWh	0.03166	/kWh	Super Off-Peak	N/A	/kWh	N/A	86
87												87
88	R-3	Residential Service	Rate	Summer	Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	88
89	Time-of-Use 4pm-7pm	Time of Use with			All On-Peak kW	16.875	/kW	All On-Peak kW	21.113	/kW	4.238	89
90	Weekdays with Demand	Demand Charge			All On-Peak kWh	0.12414	/kWh	All On-Peak kWh	0.15250	/kWh	0.02836	90
91					All Off-Peak kWh	0.05276	/kWh	All Off-Peak kWh	0.06319	/kWh	0.01043	91
92				Winter								92
93					Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	93
94					All On-Peak kW	11.845	/kW	All On-Peak kW	14.820	/kW	2.975	94
95					All On-Peak kWh	0.08711	/kWh	All On-Peak kWh	0.10615	/kWh	0.01904	95
96					All Off-Peak kWh	0.05267	/kWh	Off-Peak kWh	0.06306	/kWh	0.01039	96
97					All Super Off-Peak kWh	0.03166	/kWh	Super Off-Peak	0.03676	/kWh	0.00510	97
98												98

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
99	R-TECH	Residential Service	Rate	Summer	Basic Service Charge	$ 0.473	/day	Basic Service Charge	$ 0.591	/day	$ 0.118	99
100	Technology Time-of-Use	Time of Use with			All On-Peak kW	19.434	/kW	All On-Peak kW	24.284	/kW	4.850	100
101	with Demand	Demand Charge			Off-Peak first 5 kW	-	/kW	Off-Peak first 5 kW	-	/kW	-	101
102					Off-Peak all remaining kW	6.239	/kW	Off-Peak all remaining kW	7.797	/kW	1.558	102
103					All On-Peak kWh	0.05613	/kWh	All On-Peak kWh	0.06733	/kWh	0.01120	103
104					All Off-Peak kWh	0.04653	/kWh	All Off-Peak kWh	0.05533	/kWh	0.00880	104
105												105
106												106
107			Rate	Winter	Basic Service Charge	$ 0.473	/day	Basic Service Charge	$ 0.591	/day	$ 0.118	107
108					All On-Peak kW	13.676	/kW	All On-Peak kW	17.089	/kW	3.413	108
109					Off-Peak first 5 kW	-	/kW	Off-Peak first 5 kW	-	/kW	-	109
110					Off-Peak all remaining kW	6.239	/kW	Off-Peak all remaining kW	7.797	/kW	1.558	110
111					All On-Peak kWh	0.04653	/kWh	All On-Peak kWh	0.05533	/kWh	0.00880	111
112					Off-Peak kWh	0.04653	/kWh	Off-Peak kWh	0.05533	/kWh	0.00880	112
113												113
114	R-EV	Residential Service	Rate	Sum	Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	114
115	Residential	Time of Use			On-Peak kWh	0.40685	/kWh	On-Peak kWh	0.49709	/kWh	0.09024	115
116	Electric Vehicle				Off-Peak kWh	0.10789	/kWh	Off-Peak kWh	0.13202	/kWh	0.02413	116
117					Super Off-Peak kWh	0.03166	/kWh	Super Off-Peak kWh	0.03676	/kWh	0.00510	117
118												118
119			Rate	Win	Basic Service Charge	$ 0.400	/day	Basic Service Charge	$ 0.500	/day	$ 0.100	119
120					On-Peak kWh	0.38477	/kWh	On-Peak kWh	0.46998	/kWh	0.08521	120
121					Off-Peak kWh	0.10790	/kWh	Off-Peak kWh	0.13203	/kWh	0.02413	121
122					Super Off-Peak kWh	0.03166	/kWh	Super Off-Peak kWh	0.03676	/kWh	0.00510	122
123												123
124												124
125	E-12	Residential Service	Rate	Summer	Basic Service Charge	$ 0.320	/day	Basic Service Charge	$ 0.395	/day	$ 0.075	125
126	Solar Legacy				First 400 kWh	0.10828	/kWh	First 400 kWh	0.13213	/kWh	0.02385	126
127					Next 400 kWh	0.15429	/kWh	Next 400 kWh	0.18914	/kWh	0.03485	127
128					Next 2200 kWh	0.18046	/kWh	Next 2200 kWh	0.22158	/kWh	0.04112	128
129					All additional kWh	0.19241	/kWh	All additional kWh	0.23639	/kWh	0.04398	129
130												130
131				Winter	Basic Service Charge	$ 0.320	/day	Basic Service Charge	$ 0.395	/day	$ 0.075	131
132					All kWh	0.10528	/kWh	All kWh	0.12841	/kWh	0.02313	132
133												133
134	ET-1	Residential Service	Rate	Summer	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.772	/day	$ 0.150	134
135	Solar Legacy	Time of Use			All On-Peak kWh	0.20048	/kWh	All On-Peak kWh	0.24749	/kWh	0.04701	135
136					All Off-Peak kWh	0.06512	/kWh	All Off-Peak kWh	0.07894	/kWh	0.01382	136
137												137
138				Winter	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.772	/day	$ 0.150	138
139					All On-Peak kWh	0.16274	/kWh	All On-Peak kWh	0.20050	/kWh	0.03776	139
140					All Off-Peak kWh	0.06222	/kWh	All Off-Peak kWh	0.07533	/kWh	0.01311	140
141												141
142	ET-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.772	/day	$ 0.150	142
143	Solar Legacy	Time of Use			All On-Peak kWh	0.27307	/kWh	All On-Peak kWh	0.33776	/kWh	0.06469	143
144					All Off-Peak kWh	0.06906	/kWh	All Off-Peak kWh	0.08383	/kWh	0.01477	144
145												145
146				Winter	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.772	/day	$ 0.150	146
147					All On-Peak kWh	0.22178	/kWh	All On-Peak kWh	0.27392	/kWh	0.05214	147
148					All Off-Peak kWh	0.06810	/kWh	All Off-Peak kWh	0.08263	/kWh	0.01453	148
149												149

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
150	ECT-1R	Residential Service	Rate	Summer	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.770	/day	$ 0.148	150
151	Solar Legacy	Time of Use with			All On-Peak kW	15.170	/kW	All On-Peak kW	18.839	/kW	3.669	151
152		Demand Charge			All On-Peak kWh	0.08245	/kWh	All On-Peak kWh	0.10029	/kWh	0.01784	152
153					All Off-Peak kWh	0.04610	/kWh	All Off-Peak kWh	0.05515	/kWh	0.00905	153
154												154
155				Winter	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.770	/day	$ 0.148	155
156					All On-Peak kW	10.524	/kW	All On-Peak kW	13.070	/kW	2.546	156
157					All On-Peak kWh	0.06292	/kWh	All On-Peak kWh	0.07603	/kWh	0.01311	157
158					All Off-Peak kWh	0.04478	/kWh	All Off-Peak kWh	0.05351	/kWh	0.00873	158
159												159
160	ECT-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.770	/day	$ 0.148	160
161	Solar Legacy	Time of Use with			All On-Peak kW	15.096	/kW	All On-Peak kW	18.743	/kW	3.647	161
162		Demand Charge			All On-Peak kWh	0.09952	/kWh	All On-Peak kWh	0.12147	/kWh	0.02195	162
163					All Off-Peak kWh	0.04976	/kWh	All Off-Peak kWh	0.05969	/kWh	0.00993	163
164												164
165				Winter	Basic Service Charge	$ 0.622	/day	Basic Service Charge	$ 0.770	/day	$ 0.148	165
166					All On-Peak kW	10.399	/kW	All On-Peak kW	12.911	/kW	2.512	166
167					All On-Peak kWh	0.06463	/kWh	All On-Peak kWh	0.07815	/kWh	0.01352	167
168					All Off-Peak kWh	0.04629	/kWh	All Off-Peak kWh	0.05538	/kWh	0.00909	168
169												169
170	CPP-RES	Residential Service	Rate	Summer	Critical Peak Price	$ 0.25000	/kWh	Critical Peak Price	$ 0.25000	/kWh	$ -	170
171		Critical Peak Pricing			Energy Discount	(0.012143)	/kWh	Energy Discount	(0.012143)	/kWh	-	171
172												172
173	E-20	General Service	Rate	Summer	Basic Service Charge	$ 1.932	/day	Basic Service Charge	$ 2.418	/day	$ 0.486	173
174		Time of Use for			All On-Peak kW	3.762	/kW	All On-Peak kW	4.008	/kW	0.246	174
175		Religious Houses of			Excess Off-Peak kW	2.301	/kW	Excess Off-Peak kW	2.935	/kW	0.634	175
176		Worship			All On-Peak kWh	0.14849	/kWh	All On-Peak kWh	0.18924	/kWh	0.04075	176
177					All Off-Peak kWh	0.07259	/kWh	All Off-Peak kWh	0.09244	/kWh	0.01985	177
178												178
179			Rate	Winter	Basic Service Charge	$ 1.932	/day	Basic Service Charge	$ 2.418	/day	$ 0.486	179
180					All On-Peak kW	3.762	/kW	All On-Peak kW	4.008	/kW	0.246	180
181					Excess Off-Peak kW	2.301	/kW	Excess Off-Peak kW	2.935	/kW	0.634	181
182					All On-Peak kWh	0.13097	/kWh	All On-Peak kWh	0.16689	/kWh	0.03592	182
183					All Off-Peak kWh	0.06522	/kWh	All Off-Peak kWh	0.08304	/kWh	0.01782	183
184												184
185	E-30	Extra Small General	Rate	Summer	Basic Service Charge	$ 0.391	/day	Basic Service Charge	$ 0.487	/day	$ 0.096	185
186		Service Unmetered			All kWh	0.13406	/kWh	All kWh	0.16493	/kWh	0.03087	186
187												187
188				Winter	Basic Service Charge	$ 0.391	/day	Basic Service Charge	$ 0.487	/day	$ 0.096	188
189					All kWh	0.12106	/kWh	All kWh	0.14874	/kWh	0.02768	189
190												190

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
191	E-32 XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	191
192		20 kW or Less			BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	192
193					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	193
194					First 5,000 kWh: Secondary	0.13104	/kWh	First 5,000 kWh: Secondary	0.16199	/kWh	0.03095	194
195					All remaining kWh: Secondary	0.07298	/kWh	All remaining kWh: Secondary	0.08930	/kWh	0.0163	195
196					First 5,000 kWh: Primary	0.12767	/kWh	First 5,000 kWh: Primary	0.15777	/kWh	0.0301	196
197					All remaining kWh: Primary	0.06929	/kWh	All remaining kWh: Primary	0.08468	/kWh	0.0154	197
198												198
199				Winter	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	199
200					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	200
201					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	201
202					First 5,000 kWh: Secondary	0.11527	/kWh	First 5,000 kWh: Secondary	0.14227	/kWh	0.02700	202
203					All remaining kWh: Secondary	0.05689	/kWh	All remaining kWh: Secondary	0.06916	/kWh	0.01227	203
204					First 5,000 kWh: Primary	0.11185	/kWh	First 5,000 kWh: Primary	0.13799	/kWh	0.02614	204
205					All remaining kWh: Primary	0.05351	/kWh	All remaining kWh: Primary	0.06493	/kWh	0.01142	205
206												206
207	E-32 XS D	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	207
208		20 kW or Less			BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.48600	208
209		Demand Rate			BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.19200	209
210					All kW: Secondary	6.686	/kW	All kW: Secondary	8.393	/kW	1.707	210
211					All kW: Primary	4.167	/kW	All kW: Primary	5.231	/kW	1.064	211
212					All kWh: Secondary	0.10266	/kWh	All kWh: Secondary	0.12676	/kWh	0.02410	212
213					All kWh: Primary	0.09687	/kWh	All kWh: Primary	0.11949	/kWh	0.02262	213
214												214
215				Winter	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	215
216					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	216
217					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	217
218					All kW: Secondary	6.686	/kW	All kW: Secondary	8.393	/kW	1.707	218
219					All kW: Primary	4.167	/kW	All kW: Primary	5.231	/kW	1.064	219
220					All kWh: Secondary	0.08414	/kWh	All kWh: Secondary	0.10350	/kWh	0.01936	220
221					All kWh: Primary	0.07853	/kWh	All kWh: Primary	0.09646	/kWh	0.01793	221
222												222
223	E-32 S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	223
224		21-100 kW			BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	224
225					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	225
226					First 100 kW: Secondary	11.060	/kW	First 100 kW: Secondary	13.177	/kW	2.117	226
227					All remaining kW: Secondary	6.476	/kW	All remaining kW: Secondary	7.408	/kW	0.932	227
228					First 100 kW: Primary	10.352	/kW	First 100 kW: Primary	12.286	/kW	1.934	228
229					All remaining kW: Primary	5.768	/kW	All remaining kW: Primary	6.517	/kW	0.749	229
230					First 200 kWh per kW	0.10307	/kWh	First 200 kWh per kW	0.12963	/kWh	0.02656	230
231					All remaining kWh	0.06460	/kWh	All remaining kWh	0.08121	/kWh	0.01661	231
232												232
233				Winter	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	233
234					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	234
235					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	235
236					First 100 kW: Secondary	11.060	/kW	First 100 kW: Secondary	13.177	/kW	2.117	236
237					All remaining kW: Secondary	6.476	/kW	All remaining kW: Secondary	7.408	/kW	0.932	237
238					First 100 kW: Primary	10.352	/kW	First 100 kW: Primary	12.286	/kW	1.934	238
239					All remaining kW: Primary	5.768	/kW	All remaining kW: Primary	6.517	/kW	0.749	239
240					First 200 kWh per kW	0.08783	/kWh	First 200 kWh per kW	0.11045	/kWh	0.02262	240
241					All remaining kWh	0.04937	/kWh	All remaining kWh	0.06204	/kWh	0.01267	241
242												242

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
243	E-32 M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	243
244		101- 400 kW			BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	244
245					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	245
246					BSC: Transmission Meters	34.851	/day	BSC: Transmission Meters	44.093	/day	9.242	246
247					First 100 kW: Secondary	11.713	/kW	First 100 kW: Secondary	14.007	/kW	2.294	247
248					All remaining kW: Secondary	6.754	/kW	All remaining kW: Secondary	7.762	/kW	1.008	248
249					First 100 kW: Primary	10.855	/kW	First 100 kW: Primary	12.927	/kW	2.072	249
250					All remaining kW: Primary	6.049	/kW	All remaining kW: Primary	6.874	/kW	0.825	250
251					First 100 kW: Transmission	8.780	/kW	First 100 kW: Transmission	10.313	/kW	1.533	251
252					All remaining kW: Transmission	3.825	/kW	All remaining kW: Transmission	4.073	/kW	0.248	252
253					First 200 kWh per kW	0.10065	/kWh	First 200 kWh per kW	0.12666	/kWh	0.02601	253
254					All remaining kWh	0.06210	/kWh	All remaining kWh	0.07811	/kWh	0.01601	254
255												255
256			Rate	Winter	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	256
257					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	257
258					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	258
259					BSC: Transmission Meters	34.851	/day	BSC: Transmission Meters	44.093	/day	9.242	259
260					First 100 kW: Secondary	11.713	/kW	First 100 kW: Secondary	14.007	/kW	2.294	260
261					All remaining kW: Secondary	6.754	/kW	All remaining kW: Secondary	7.762	/kW	1.008	261
262					First 100 kW: Primary	10.855	/kW	First 100 kW: Primary	12.927	/kW	2.072	262
263					All remaining kW: Primary	6.049	/kW	All remaining kW: Primary	6.874	/kW	0.825	263
264					First 100 kW: Transmission	8.780	/kW	First 100 kW: Transmission	10.313	/kW	1.533	264
265					All remaining kW: Transmission	3.825	/kW	All remaining kW: Transmission	4.073	/kW	0.248	265
266					First 200 kWh per kW	0.08532	/kWh	First 200 kWh per kW	0.10727	/kWh	0.02195	266
267					All remaining kWh	0.04678	/kWh	All remaining kWh	0.05891	/kWh	0.01213	267
268												268
269	E-32 L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 2.891	/day	BSC: Self-Contained Meters	$ 3.657	/day	$ 0.766	269
270		401 kW and above			BSC: Instrument-rated Meters	3.705	/day	BSC: Instrument-rated Meters	4.687	/day	0.982	270
271					BSC: Primary Meters	6.477	/day	BSC: Primary Meters	8.195	/day	1.718	271
272					BSC: Transmission Meters	36.639	/day	BSC: Transmission Meters	46.362	/day	9.723	272
273					First 100 kW: Secondary	24.097	/kW	First 100 kW: Secondary	29.731	/kW	5.634	273
274					All remaining kW: Secondary	16.760	/kW	All remaining kW: Secondary	20.446	/kW	3.686	274
275					First 100 kW: Primary	21.903	/kW	First 100 kW: Primary	26.954	/kW	5.051	275
276					All remaining kW: Primary	15.633	/kW	All remaining kW: Primary	19.020	/kW	3.387	276
277					First 100 kW: Transmission	16.778	/kW	First 100 kW: Transmission	20.469	/kW	3.691	277
278					All remaining kW: Transmission	11.233	/kW	All remaining kW: Transmission	13.452	/kW	2.219	278
279					All kWh	0.05258	/kWh	All kWh	0.06642	/kWh	0.01384	279
280					Aggregation Discount	(0.00234)	/kWh	Aggregation Discount	(0.00293)	/kWh	(0.00059)	280
281												281
282			Rate	Winter	BSC: Self-Contained Meters	$ 2.891	/day	BSC: Self-Contained Meters	$ 3.657	/day	$ 0.766	282
283					BSC: Instrument-rated Meters	3.705	/day	BSC: Instrument-rated Meters	4.687	/day	0.982	283
284					BSC: Primary Meters	6.477	/day	BSC: Primary Meters	8.195	/day	1.718	284
285					BSC: Transmission Meters	36.639	/day	BSC: Transmission Meters	46.362	/day	9.723	285
286					First 100 kW: Secondary	24.097	/kW	First 100 kW: Secondary	29.731	/kW	5.634	286
287					All remaining kW: Secondary	16.760	/kW	All remaining kW: Secondary	20.446	/kW	3.686	287
288					First 100 kW: Primary	21.903	/kW	First 100 kW: Primary	26.954	/kW	5.051	288
289					All remaining kW: Primary	15.633	/kW	All remaining kW: Primary	19.020	/kW	3.387	289
290					First 100 kW: Transmission	16.778	/kW	First 100 kW: Transmission	20.469	/kW	3.691	290
291					All remaining kW: Transmission	11.233	/kW	All remaining kW: Transmission	13.452	/kW	2.219	291
292					All kWh	0.03542	/kWh	All kWh	0.04470	/kWh	0.00928	292
293					Aggregation Discount	(0.00234)	/kWh	Aggregation Discount	(0.00293)	/kWh	(0.00059)	293

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
294												294
295	E-32TOU XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	295
296		Time of Use			BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	296
297		20 kW or Less			BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	297
298					kW - secondary - on	4.386	/kW	kW - secondary - on	5.497	/kW	1.111	298
299					kW - secondary - off	2.508	/kW	kW - secondary - off	3.143	/kW	0.635	299
300					kW - primary - on	3.810	/kW	kW - primary - on	4.775	/kW	0.965	300
301					kW - primary - off	1.508	/kW	kW - primary - off	1.890	/kW	0.382	301
302					kWh - secondary - on	0.14427	/kWh	kWh - secondary - on	0.17871	/kWh	0.03444	302
303					kWh - secondary - off	0.11068	/kWh	kWh - secondary - off	0.13662	/kWh	0.02594	303
304					kWh - primary - on	0.14233	/kWh	kWh - primary - on	0.17628	/kWh	0.03395	304
305					kWh - primary - off	0.10467	/kWh	kWh - primary - off	0.12909	/kWh	0.02442	305
306												306
307				Winter	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	307
308					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	308
309					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	309
310					kW - secondary - on	4.386	/kW	kW - secondary - on	5.497	/kW	1.111	310
311					kW - secondary - off	2.508	/kW	kW - secondary - off	3.143	/kW	0.635	311
312					kW - primary - on	3.810	/kW	kW - primary - on	4.775	/kW	0.965	312
313					kW - primary - off	1.508	/kW	kW - primary - off	1.890	/kW	0.382	313
314					kWh - secondary - on	0.11536	/kWh	kWh - secondary - on	0.14248	/kWh	0.02712	314
315					kWh - secondary - off	0.08852	/kWh	kWh - secondary - off	0.10885	/kWh	0.02033	315
316					kWh - primary - on	0.11342	/kWh	kWh - primary - on	0.14005	/kWh	0.02663	316
317					kWh - primary - off	0.08251	/kWh	kWh - primary - off	0.10132	/kWh	0.01881	317
318												318
319	E-32TOU S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	319
320		Time of Use			BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	320
321		21-100 kW			BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	321
322					First 100 On-Peak kW: Secondary	19.372	/kW	First 100 On-Peak kW: Secondary	23.541	/kW	4.169	322
323					All remaining On-Peak kW: Secondary	9.953	/kW	All remaining On-Peak kW: Secondary	11.743	/kW	1.790	323
324					First 100 Off-Peak kW: Secondary	7.601	/kW	First 100 Off-Peak kW: Secondary	9.522	/kW	1.921	324
325					All remaining Off-Peak kW: Secondary	2.614	/kW	All remaining Off-Peak kW: Secondary	3.275	/kW	0.661	325
326					First 100 On-Peak kW: Primary	18.431	/kW	First 100 On-Peak kW: Primary	22.363	/kW	3.932	326
327					All remaining On-Peak kW: Primary	9.814	/kW	All remaining On-Peak kW: Primary	11.569	/kW	1.755	327
328					First 100 Off-Peak kW: Primary	6.422	/kW	First 100 Off-Peak kW: Primary	8.045	/kW	1.623	328
329					All remaining Off-Peak kW: Primary	2.453	/kW	All remaining Off-Peak kW: Primary	3.073	/kW	0.620	329
330					All On-Peak kWh:	0.06935	/kWh	All On-Peak kWh:	0.08679	/kWh	0.01744	330
331					All Off-Peak kWh:	0.05276	/kWh	All Off-Peak kWh:	0.06601	/kWh	0.01325	331
332												332
333				Winter	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	333
334					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	334
335					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	335
336					First 100 On-Peak kW: Secondary	19.372	/kW	First 100 On-Peak kW: Secondary	23.541	/kW	4.169	336
337					All remaining On-Peak kW: Secondary	9.953	/kW	All remaining On-Peak kW: Secondary	11.743	/kW	1.790	337
338					First 100 Off-Peak kW: Secondary	7.601	/kW	First 100 Off-Peak kW: Secondary	9.522	/kW	1.921	338
339					All remaining Off-Peak kW: Secondary	2.614	/kW	All remaining Off-Peak kW: Secondary	3.275	/kW	0.661	339
340					First 100 On-Peak kW: Primary	18.431	/kW	First 100 On-Peak kW: Primary	22.363	/kW	3.932	340
341					All remaining On-Peak kW: Primary	9.814	/kW	All remaining On-Peak kW: Primary	11.569	/kW	1.755	341
342					First 100 Off-Peak kW: Primary	6.422	/kW	First 100 Off-Peak kW: Primary	8.045	/kW	1.623	342
343					All remaining Off-Peak kW: Primary	2.453	/kW	All remaining Off-Peak kW: Primary	3.073	/kW	0.620	343
344					All On-Peak kWh:	0.05434	/kWh	All On-Peak kWh:	0.06799	/kWh	0.01365	344
345					All Off-Peak kWh:	0.04010	/kWh	All Off-Peak kWh:	0.05016	/kWh	0.01006	345

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
346												346
347	E-32TOU M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	347
348		Time of Use			BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	348
349		101- 400 kW			BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	349
350					BSC: Transmission Meters	34.851	/day	BSC: Transmission Meters	44.093	/day	9.242	350
351					First 100 On-Peak kW: Secondary	17.493	/kW	First 100 On-Peak kW: Secondary	21.244	/kW	3.751	351
352					All remaining On-Peak kW: Secondary	11.326	/kW	All remaining On-Peak kW: Secondary	13.495	/kW	2.169	352
353					First 100 Off-Peak kW: Secondary	6.438	/kW	First 100 Off-Peak kW: Secondary	8.089	/kW	1.651	353
354					All remaining Off-Peak kW: Secondary	3.170	/kW	All remaining Off-Peak kW: Secondary	3.983	/kW	0.813	354
355					First 100 On-Peak kW: Primary	16.878	/kW	First 100 On-Peak kW: Primary	20.471	/kW	3.593	355
356					All remaining On-Peak kW: Primary	11.233	/kW	All remaining On-Peak kW: Primary	13.378	/kW	2.145	356
357					First 100 Off-Peak kW: Primary	5.666	/kW	First 100 Off-Peak kW: Primary	7.119	/kW	1.453	357
358					All remaining Off-Peak kW: Primary	3.064	/kW	All remaining Off-Peak kW: Primary	3.849	/kW	0.785	358
359					First 100 On-Peak kW: Transmission	15.775	/kW	First 100 On-Peak kW: Transmission	19.085	/kW	3.310	359
360					All remaining On-Peak kW: Transmission	10.853	/kW	All remaining On-Peak kW: Transmission	12.901	/kW	2.048	360
361					First 100 Off-Peak kW: Transmission	4.792	/kW	First 100 Off-Peak kW: Transmission	6.021	/kW	1.229	361
362					All remaining Off-Peak kW: Transmission	2.921	/kW	All remaining Off-Peak kW: Transmission	3.670	/kW	0.749	362
363					All On-Peak kWh:	0.06870	/kWh	All On-Peak kWh:	0.08623	/kWh	0.01753	363
364					All Off-Peak kWh:	0.05713	/kWh	All Off-Peak kWh:	0.07170	/kWh	0.01457	364
365												365
366				Winter	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	366
367					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	367
368					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	368
369					BSC: Transmission Meters	34.851	/day	BSC: Transmission Meters	44.093	/day	9.242	369
370					First 100 On-Peak kW: Secondary	17.493	/kW	First 100 On-Peak kW: Secondary	21.244	/kW	3.751	370
371					All remaining On-Peak kW: Secondary	11.326	/kW	All remaining On-Peak kW: Secondary	13.495	/kW	2.169	371
372					First 100 Off-Peak kW: Secondary	6.438	/kW	First 100 Off-Peak kW: Secondary	8.089	/kW	1.651	372
373					All remaining Off-Peak kW: Secondary	3.170	/kW	All remaining Off-Peak kW: Secondary	3.983	/kW	0.813	373
374					First 100 On-Peak kW: Primary	16.878	/kW	First 100 On-Peak kW: Primary	20.471	/kW	3.593	374
375					All remaining On-Peak kW: Primary	11.233	/kW	All remaining On-Peak kW: Primary	13.378	/kW	2.145	375
376					First 100 Off-Peak kW: Primary	5.666	/kW	First 100 Off-Peak kW: Primary	7.119	/kW	1.453	376
377					All remaining Off-Peak kW: Primary	3.064	/kW	All remaining Off-Peak kW: Primary	3.849	/kW	0.785	377
378					First 100 On-Peak kW: Transmission	15.775	/kW	First 100 On-Peak kW: Transmission	19.085	/kW	3.310	378
379					All remaining On-Peak kW: Transmission	10.853	/kW	All remaining On-Peak kW: Transmission	12.901	/kW	2.048	379
380					First 100 Off-Peak kW: Transmission	4.792	/kW	First 100 Off-Peak kW: Transmission	6.021	/kW	1.229	380
381					All remaining Off-Peak kW: Transmission	2.921	/kW	All remaining Off-Peak kW: Transmission	3.670	/kW	0.749	381
382					All On-Peak kWh:	0.05553	/kWh	All On-Peak kWh:	0.06968	/kWh	0.01415	382
383					All Off-Peak kWh:	0.04395	/kWh	All Off-Peak kWh:	0.05513	/kWh	0.01118	383

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
384												384
385	E-32TOU L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 2.891	/day	BSC: Self-Contained Meters	$ 3.657	/day	$ 0.766	385
386		Time of Use			BSC: Instrument-rated Meters	3.705	/day	BSC: Instrument-rated Meters	4.687	/day	0.982	386
387		401 kW and above			BSC: Primary Meters	6.477	/day	BSC: Primary Meters	8.195	/day	1.718	387
388					BSC: Transmission Meters	36.639	/day	BSC: Transmission Meters	46.362	/day	9.723	388
389					First 100 On-Peak kW: Secondary	16.692	/kW	First 100 On-Peak kW: Secondary	20.338	/kW	3.646	389
390					All remaining On-Peak kW: Secondary	11.285	/kW	All remaining On-Peak kW: Secondary	13.505	/kW	2.220	390
391					First 100 Off-Peak kW: Secondary	6.042	/kW	First 100 Off-Peak kW: Secondary	7.636	/kW	1.594	391
392					All remaining Off-Peak kW: Secondary	3.178	/kW	All remaining Off-Peak kW: Secondary	4.017	/kW	0.839	392
393					First 100 On-Peak kW: Primary	16.150	/kW	First 100 On-Peak kW: Primary	19.653	/kW	3.503	393
394					All remaining On-Peak kW: Primary	11.203	/kW	All remaining On-Peak kW: Primary	13.401	/kW	2.198	394
395					First 100 Off-Peak kW: Primary	5.364	/kW	First 100 Off-Peak kW: Primary	6.779	/kW	1.415	395
396					All remaining Off-Peak kW: Primary	3.085	/kW	All remaining Off-Peak kW: Primary	3.899	/kW	0.814	396
397					First 100 On-Peak kW: Transmission	15.185	/kW	First 100 On-Peak kW: Transmission	18.433	/kW	3.248	397
398					All remaining On-Peak kW: Transmission	10.037	/kW	All remaining On-Peak kW: Transmission	11.927	/kW	1.890	398
399					First 100 Off-Peak kW: Transmission	4.598	/kW	First 100 Off-Peak kW: Transmission	5.811	/kW	1.213	399
400					All remaining Off-Peak kW: Transmission	2.957	/kW	All remaining Off-Peak kW: Transmission	3.737	/kW	0.780	400
401					All On-Peak kWh:	0.06665	/kWh	All On-Peak kWh:	0.08411	/kWh	0.01746	401
402					All Off-Peak kWh:	0.05452	/kWh	All Off-Peak kWh:	0.06879	/kWh	0.01427	402
403												403
404				Winter	BSC: Self-Contained Meters	$ 2.891	/day	BSC: Self-Contained Meters	$ 3.657	/day	$ 0.766	404
405					BSC: Instrument-rated Meters	3.705	/day	BSC: Instrument-rated Meters	4.687	/day	0.982	405
406					BSC: Primary Meters	6.477	/day	BSC: Primary Meters	8.195	/day	1.718	406
407					BSC: Transmission Meters	36.639	/day	BSC: Transmission Meters	46.362	/day	9.723	407
408					First 100 On-Peak kW: Secondary	16.692	/kW	First 100 On-Peak kW: Secondary	20.338	/kW	3.646	408
409					All remaining On-Peak kW: Secondary	11.285	/kW	All remaining On-Peak kW: Secondary	13.505	/kW	2.220	409
410					First 100 Off-Peak kW: Secondary	6.042	/kW	First 100 Off-Peak kW: Secondary	7.636	/kW	1.594	410
411					All remaining Off-Peak kW: Secondary	3.178	/kW	All remaining Off-Peak kW: Secondary	4.017	/kW	0.839	411
412					First 100 On-Peak kW: Primary	16.150	/kW	First 100 On-Peak kW: Primary	19.653	/kW	3.503	412
413					All remaining On-Peak kW: Primary	11.203	/kW	All remaining On-Peak kW: Primary	13.401	/kW	2.198	413
414					First 100 Off-Peak kW: Primary	5.364	/kW	First 100 Off-Peak kW: Primary	6.779	/kW	1.415	414
415					All remaining Off-Peak kW: Primary	3.085	/kW	All remaining Off-Peak kW: Primary	3.899	/kW	0.814	415
416					First 100 On-Peak kW: Transmission	15.185	/kW	First 100 On-Peak kW: Transmission	18.433	/kW	3.248	416
417					All remaining On-Peak kW: Transmission	10.037	/kW	All remaining On-Peak kW: Transmission	11.927	/kW	1.890	417
418					First 100 Off-Peak kW: Transmission	4.598	/kW	First 100 Off-Peak kW: Transmission	5.811	/kW	1.213	418
419					All remaining Off-Peak kW: Transmission	2.957	/kW	All remaining Off-Peak kW: Transmission	3.737	/kW	0.780	419
420					All On-Peak kWh:	0.05286	/kWh	All On-Peak kWh:	0.06669	/kWh	0.01383	420
421					All Off-Peak kWh:	0.04073	/kWh	All Off-Peak kWh:	0.05136	/kWh	0.01063	421
422												422
423	E-32 L SP	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 2.891	/day	BSC: Self-Contained Meters	$ 3.657	/day	$ 0.766	423
424		Time of Use Storage Pilot			BSC: Instrument-rated Meters	3.705	/day	BSC: Instrument-rated Meters	4.687	/day	0.982	424
425		401 kW and above			BSC: Primary Meters	6.477	/day	BSC: Primary Meters	8.195	/day	1.718	425
426					BSC: Transmission Meters	36.639	/day	BSC: Transmission Meters	46.362	/day	9.723	426
427					On-Peak kW: Secondary	12.654	/kW	On-Peak and Remaining kW: Secondary	15.251	/kW	2.597	427
428					Remaining kW: Secondary	3.763	/kW	Off-Peak Excess kW: Secondary	4.762	/kW	0.999	428
429					On-Peak kW: Primary	11.830	/kW	On-Peak and Remaining kW: Primary	14.208	/kW	2.378	429
430					Remaining kW: Primary	3.446	/kW	Off-Peak Excess kW: Primary	4.361	/kW	0.915	430
431					On-Peak kW: Transmission	10.184	/kW	On-Peak and Remaining kW: Transmission	12.126	/kW	1.942	431
432					Remaining kW: Transmission	2.813	/kW	Off-Peak Excess kW: Transmission	3.560	/kW	0.747	432
433					All On-Peak kWh	0.06534	/kWh	All On-Peak kWh	0.08255	/kWh	0.01721	433
434					All Remaining kWh	0.06189	/kWh	All Remaining kWh	0.07818	/kWh	0.01629	434
435					All Off-Peak kWh	0.05613	/kWh	All Off-Peak kWh	0.07090	/kWh	0.01477	435
436												436

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
437	E-32 L SP	General Service	Rate	Non Summer	BSC: Self-Contained Meters	$ 2.891	/day	BSC: Self-Contained Meters	$ 3.657	/day	$ 0.766	437
438	(continued)	Time of Use Storage Pilot			BSC: Instrument-rated Meters	3.705	/day	BSC: Instrument-rated Meters	4.687	/day	0.982	438
439		401 kW and above			BSC: Primary Meters	6.477	/day	BSC: Primary Meters	8.195	/day	1.718	439
440					BSC: Transmission Meters	36.639	/day	BSC: Transmission Meters	46.362	/day	9.723	440
441					On-Peak kW: Secondary	11.419	/kW	On-Peak and Remaining kW: Secondary	13.688	/kW	2.269	441
442					Remaining kW: Secondary	3.288	/kW	Off-Peak Excess kW: Secondary	4.161	/kW	0.873	442
443					On-Peak kW: Primary	10.595	/kW	On-Peak and Remaining kW: Primary	12.646	/kW	2.051	443
444					Remaining kW: Primary	2.971	/kW	Off-Peak Excess kW: Primary	3.760	/kW	0.789	444
445					On-Peak kW: Transmission	8.949	/kW	On-Peak and Remaining kW: Transmission	10.563	/kW	1.614	445
446					Remaining kW: Transmission	2.338	/kW	Off-Peak Excess kW: Transmission	2.959	/kW	0.621	446
447					All On-Peak kWh	0.05178	/kWh	All On-Peak kWh	0.06539	/kWh	0.01361	447
448					All Remaining kWh	0.04946	/kWh	All Remaining kWh	0.06246	/kWh	0.01300	448
449					All Off-Peak kWh	0.04337	/kWh	All Off-Peak kWh	0.05475	/kWh	0.01138	449
450												450
451	E-34	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 4.033	/day	BSC: Self-Contained Meters	$ 5.156	/day	$ 1.123	451
452		General Service			BSC: Instrument-rated Meters	4.818	/day	BSC: Instrument-rated Meters	6.159	/day	1.341	452
453					BSC: Primary Meters	7.489	/day	BSC: Primary Meters	9.573	/day	2.084	453
454					BSC: Military Bases	7.489	/day	BSC: Military Bases	9.573	/day	2.084	454
455					BSC: Transmission Meters	36.560	/day	BSC: Transmission Meters	46.732	/day	10.172	455
456					All kW: Secondary	20.432	/kW	All kW: Secondary	25.216	/kW	4.784	456
457					All kW: Primary	19.232	/kW	All kW: Primary	23.682	/kW	4.450	457
458					All kW: Primary on Military Bases	14.176	/kW	All kW: Primary on Military Bases	17.219	/kW	3.043	458
459					All kW: Transmission	13.311	/kW	All kW: Transmission	16.114	/kW	2.803	459
460					All kWh	0.03700	/kWh	All kWh	0.04714	/kWh	0.01014	460
461												461
462	E-35	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 4.033	/day	BSC: Self-Contained Meters	$ 5.156	/day	$ 1.123	462
463		General Service			BSC: Instrument-rated Meters	4.818	/day	BSC: Instrument-rated Meters	6.159	/day	1.341	463
464		Time Of Use			BSC: Primary Meters	7.489	/day	BSC: Primary Meters	9.573	/day	2.084	464
465					BSC: Military Bases	7.489	/day	BSC: Military Bases	9.573	/day	2.084	465
466					BSC: Transmission Meters	36.560	/day	BSC: Transmission Meters	46.732	/day	10.172	466
467					All On-Peak kW: Secondary	17.559	/kW	All On-Peak kW: Secondary	21.544	/kW	3.985	467
468					All Off-Peak kW: Secondary	2.661	/kW	All Off-Peak kW: Secondary	3.401	/kW	0.740	468
469					All On-Peak kW: Primary	16.408	/kW	All On-Peak kW: Primary	20.073	/kW	3.665	469
470					All Off-Peak kW: Primary	2.546	/kW	All Off-Peak kW: Primary	3.254	/kW	0.708	470
471					All On-Peak kW: Primary on Military Bases	12.058	/kW	All On-Peak kW: Primary on Military Bases	14.513	/kW	2.455	471
472					All Off-Peak kW: Primary on Military Bases	2.109	/kW	All Off-Peak kW: Primary on Military Bases	2.696	/kW	0.587	472
473					All On-Peak kW: Transmission	10.460	/kW	All On-Peak kW: Transmission	12.470	/kW	2.010	473
474					All Off-Peak kW: Transmission	1.950	/kW	All Off-Peak kW: Transmission	2.492	/kW	0.542	474
475					All On-Peak kWh	0.04072	/kWh	All On-Peak kWh	0.05189	/kWh	0.01117	475
476					All Off-Peak kWh	0.03239	/kWh	All Off-Peak kWh	0.04125	/kWh	0.00886	476
477												477
478	XHLF	Extra Large	Rate	Sum & Win	BSC: Secondary Meters	$ 4.818	/day	BSC: Secondary Meters	$ 6.159	/day	$ 1.341	478
479		General Service			BSC: Primary Meters	7.489	/day	BSC: Primary Meters	9.573	/day	2.084	479
480		High Load Factor			BSC: Transmission Meters	36.560	/day	BSC: Transmission Meters	46.732	/day	10.172	480
481					All kW: Secondary	16.989	/kW	All kW: Secondary	20.643	/kW	3.654	481
482					All kW: Primary	15.735	/kW	All kW: Primary	19.056	/kW	3.321	482
483					All kW: Transmission	12.284	/kW	All kW: Transmission	14.688	/kW	2.404	483
484					All kWh	0.03498	/kWh	All kWh	0.04416	/kWh	0.00918	484
485					Non-bypassable fuel and admin fee	0.00270	/kWh	Non-bypassable fuel and admin fee	0.00342	/kWh	0.00072	485

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
486												486
487	E-36 XL	Station Use Service	Rate	Sum & Win	Basic Service Charge	$ 7,252.78	/mo	Basic Service Charge	$ 8,911.48	/mo	$ 1,658.70	487
488					Metering Charge Company Owned	1.29%		Metering Charge Company Owned	1.29%		-	488
489					Metering Charge Customer Owned	0.35%		Metering Charge Customer Owned	0.35%		-	489
490					All kW: Secondary	5.447	/kW	All kW: Secondary	6.693	/kW	1.246	490
491					All kW: Primary	5.255	/kW	All kW: Primary	6.457	/kW	1.202	491
492					All kW: Transmission	1.701	/kW	All kW: Transmission	2.090	/kW	0.389	492
493					All kWh: Hourly Pricing Proxy plus	0.00060	/kWh	All kWh: Hourly Pricing Proxy plus	0.00074	/kWh	0.00014	493
494												494
495	E-45	Dusk to Dawn Lighting	Rate	Sum & Win	**EQUIPMENT TIERS (Company Owned)**			**EQUIPMENT TIERS (Company Owned)**				495
496		Service			Equipment Tier A	$ 5.72	/mo	Equipment Tier A	$ 6.61	/mo	$ 0.89	496
497					Equipment Tier B	6.97	/mo	Equipment Tier B	8.05	/mo	1.08	497
498					Equipment Tier C	8.36	/mo	Equipment Tier C	9.66	/mo	1.30	498
499					Equipment Tier D	9.99	/mo	Equipment Tier D	11.54	/mo	1.55	499
500					Equipment Tier E	12.64	/mo	Equipment Tier E	14.60	/mo	1.96	500
501					Equipment Tier F	14.07	/mo	Equipment Tier F	16.25	/mo	2.18	501
502					Equipment Tier G	15.38	/mo	Equipment Tier G	17.77	/mo	2.39	502
503					Equipment Tier H	17.44	/mo	Equipment Tier H	20.15	/mo	2.71	503
504					Equipment Tier I	19.40	/mo	Equipment Tier I	22.41	/mo	3.01	504
505					Equipment Tier J	23.65	/mo	Equipment Tier J	27.32	/mo	3.67	505
506					Equipment Tier K	26.29	/mo	Equipment Tier K	30.37	/mo	4.08	506
507												507
508					**EQUIPMENT TIERS (Customer Owned)**			**EQUIPMENT TIERS (Customer Owned)**				508
509					Equipment Tier A	$ 0.11	/mo	Equipment Tier A	$ 0.13	/mo	$ 0.02	509
510					Equipment Tier B	0.13	/mo	Equipment Tier B	0.15	/mo	0.02	510
511					Equipment Tier C	0.15	/mo	Equipment Tier C	0.17	/mo	0.02	511
512					Equipment Tier D	0.19	/mo	Equipment Tier D	0.22	/mo	0.03	512
513					Equipment Tier E	0.21	/mo	Equipment Tier E	0.24	/mo	0.03	513
514					Equipment Tier F	0.23	/mo	Equipment Tier F	0.27	/mo	0.04	514
515					Equipment Tier G	0.24	/mo	Equipment Tier G	0.28	/mo	0.04	515
516					Equipment Tier H	0.26	/mo	Equipment Tier H	0.30	/mo	0.04	516
517					Equipment Tier I	0.31	/mo	Equipment Tier I	0.36	/mo	0.05	517
518					Equipment Tier J	0.34	/mo	Equipment Tier J	0.39	/mo	0.05	518
519					Equipment Tier K	0.38	/mo	Equipment Tier K	0.44	/mo	0.06	519
520												520
521					Generation Charge	$ 0.06621	/kWh	Generation Charge	$ 0.07648	/kWh	$ 0.01027	521
522					T&D, RCS,SB Charge	0.02682	/kWh	T&D, RCS,SB Charge	0.03098	/kWh	0.00416	522

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	Line No.
523	E-45	Dusk to Dawn Lighting	Rate	Sum & Win								523
524	(continued)	Service			**Pole (Company Owned)**			**Pole (Company Owned)**				524
525					12ft Round Steel Flush Anchor Base - 1 Simplex	$ 12.84	/mo	12ft Round Steel Flush Anchor Base - 1 Simplex	$ 14.83	/mo	$ 1.99	525
526					22ft Round Steel Flush Anchor Base - 1 Simplex	14.45	/mo	22ft Round Steel Flush Anchor Base - 1 Simplex	16.69	/mo	2.24	526
527					25ft Round Steel Flush Anchor Base - 1 Simplex	15.64	/mo	25ft Round Steel Flush Anchor Base - 1 Simplex	18.07	/mo	2.43	527
528					30ft Round Steel Flush Anchor Base - 1 Simplex	17.96	/mo	30ft Round Steel Flush Anchor Base - 1 Simplex	20.75	/mo	2.79	528
529					32ft Round Steel Flush Anchor Base - 1 Simplex	18.87	/mo	32ft Round Steel Flush Anchor Base - 1 Simplex	21.80	/mo	2.93	529
530					12ft Round Steel Flush Anchor Base - 2 Simplex	13.69	/mo	12ft Round Steel Flush Anchor Base - 2 Simplex	15.81	/mo	2.12	530
531					22ft Round Steel Flush Anchor Base - 2 Simplex	15.73	/mo	22ft Round Steel Flush Anchor Base - 2 Simplex	18.17	/mo	2.44	531
532					25ft Round Steel Flush Anchor Base - 2 Simplex	16.41	/mo	25ft Round Steel Flush Anchor Base - 2 Simplex	18.96	/mo	2.55	532
533					30ft Round Steel Flush Anchor Base - 2 Simplex	19.07	/mo	30ft Round Steel Flush Anchor Base - 2 Simplex	22.03	/mo	2.96	533
534					32ft Round Steel Flush Anchor Base - 2 Simplex	20.34	/mo	32ft Round Steel Flush Anchor Base - 2 Simplex	23.49	/mo	3.15	534
535					13ft Square Steel Flush Anchor Base	14.72	/mo	13ft Square Steel Flush Anchor Base	17.00	/mo	2.28	535
536					15ft Square Steel Flush Anchor Base	13.15	/mo	15ft Square Steel Flush Anchor Base	15.19	/mo	2.04	536
537					23ft Square Steel Flush Anchor Base	15.60	/mo	23ft Square Steel Flush Anchor Base	18.02	/mo	2.42	537
538					25ft Square Steel Flush Anchor Base	17.15	/mo	25ft Square Steel Flush Anchor Base	19.81	/mo	2.66	538
539					28ft Square Steel Flush Anchor Base	19.04	/mo	28ft Square Steel Flush Anchor Base	21.99	/mo	2.95	539
540					32ft Square Steel Flush Anchor Base	18.93	/mo	32ft Square Steel Flush Anchor Base	21.87	/mo	2.94	540
541					12ft Concrete Flush Anchor Base	43.87	/mo	12ft Concrete Flush Anchor Base	50.67	/mo	6.80	541
542					12ft Fiberglass Flush Anchor Base	37.15	/mo	12ft Fiberglass Flush Anchor Base	42.91	/mo	5.76	542
543					16ft Decorative Transit Pedestrian Anchor Base	36.22	/mo	16ft Decorative Transit Pedestrian Anchor Base	41.84	/mo	5.62	543
544					30ft Transit Anchor Base 6"	69.93	/mo	30ft Transit Anchor Base 6"	80.78	/mo	10.85	544
545					15ft Square Hinged Flush Anchor Base	13.92	/mo	15ft Square Hinged Flush Anchor Base	16.08	/mo	2.16	545
546					19ft Round Hinged Flush Anchor Base	12.59	/mo	19ft Round Hinged Flush Anchor Base	14.54	/mo	1.95	546
547					12ft Round Steel Pedestal Anchor Base - 1 Simplex	12.35	/mo	12ft Round Steel Pedestal Anchor Base - 1 Simplex	14.27	/mo	1.92	547
548					22ft Round Steel Pedestal Anchor Base - 1 Simplex	13.97	/mo	22ft Round Steel Pedestal Anchor Base - 1 Simplex	16.14	/mo	2.17	548
549					25ft Round Steel Pedestal Anchor Base - 1 Simplex	15.14	/mo	25ft Round Steel Pedestal Anchor Base - 1 Simplex	17.49	/mo	2.35	549
550					30ft Round Steel Pedestal Anchor Base - 1 Simplex	17.48	/mo	30ft Round Steel Pedestal Anchor Base - 1 Simplex	20.19	/mo	2.71	550
551					32ft Round Steel Pedestal Anchor Base - 1 Simplex	18.37	/mo	32ft Round Steel Pedestal Anchor Base - 1 Simplex	21.22	/mo	2.85	551
552					12ft Round Steel Pedestal Anchor Base - 2 Simplex	13.19	/mo	12ft Round Steel Pedestal Anchor Base - 2 Simplex	15.24	/mo	2.05	552
553					22ft Round Steel Pedestal Anchor Base - 2 Simplex	14.74	/mo	22ft Round Steel Pedestal Anchor Base - 2 Simplex	17.03	/mo	2.29	553
554					25ft Round Steel Pedestal Anchor Base - 2 Simplex	15.91	/mo	25ft Round Steel Pedestal Anchor Base - 2 Simplex	18.38	/mo	2.47	554
555					30ft Round Steel Pedestal Anchor Base - 2 Simplex	18.58	/mo	30ft Round Steel Pedestal Anchor Base - 2 Simplex	21.46	/mo	2.88	555

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
556	E-45 (continued)	Dusk to Dawn Lighting Service	Rate	Sum & Win	32ft Round Steel Pedestal Anchor Base - 2 Simplex	$ 19.84	/mo	32ft Round Steel Pedestal Anchor Base - 2 Simplex	$ 22.92	/mo	$ 3.08	556
557					32ft Round Steel Pedestal Anchor Base - 3 Bolt	22.80	/mo	32ft Round Steel Pedestal Anchor Base - 3 Bolt	26.34	/mo	3.54	557
558						14.24	/mo		16.45	/mo	2.21	558
559					13ft Square Steel Pedestal Anchor Base	14.56	/mo	13ft Square Steel Pedestal Anchor Base	16.82	/mo	2.26	559
560					15ft Square Steel Pedestal Anchor Base	15.11	/mo	15ft Square Steel Pedestal Anchor Base	17.45	/mo	2.34	560
561					23ft Square Steel Pedestal Anchor Base	16.67	/mo	23ft Square Steel Pedestal Anchor Base	19.26	/mo	2.59	561
562					25ft Square Steel Pedestal Anchor Base	18.52	/mo	25ft Square Steel Pedestal Anchor Base	21.39	/mo	2.87	562
563					28ft Square Steel Pedestal Anchor Base	19.23	/mo	28ft Square Steel Pedestal Anchor Base	22.21	/mo	2.98	563
564					32ft Square Steel Pedestal Anchor Base 19ft Round Steel Direct Bury	19.43	/mo	32ft Square Steel Pedestal Anchor Base 19ft Round Steel Direct Bury	22.44	/mo	3.01	564
565					30ft Round Steel Direct Bury	15.17	/mo	30ft Round Steel Direct Bury	17.52	/mo	2.35	565
566					38ft Round Steel Direct Bury	18.51	/mo	38ft Round Steel Direct Bury	21.38	/mo	2.87	566
567						22.80	/mo		26.34	/mo	3.54	567
568					40ft Round Steel Direct Bury Self Support 25ft Round Steel Direct Bury Stepped	52.45	/mo	40ft Round Steel Direct Bury Self Support 25ft Round Steel Direct Bury Stepped	60.59	/mo	8.14	568
569					32ft Round Steel Direct Bury Stepped	55.24	/mo	32ft Round Steel Direct Bury Stepped	63.81	/mo	8.57	569
570					49ft Round Steel Direct Bury Stepped	68.57	/mo	49ft Round Steel Direct Bury Stepped	79.21	/mo	10.64	570
571					34ft Square Steel Direct Bury 4"	16.74	/mo	34ft Square Steel Direct Bury 4"	19.34	/mo	2.60	571
572					20ft Square Steel Direct Bury 5"	15.90	/mo	20ft Square Steel Direct Bury 5"	18.37	/mo	2.47	572
573					30ft Square Steel Direct Bury 5"	16.57	/mo	30ft Square Steel Direct Bury 5"	19.14	/mo	2.57	573
574					38ft Square Steel Direct Bury 5"	17.98	/mo	38ft Square Steel Direct Bury 5"	20.77	/mo	2.79	574
575					28ft Square Steel Direct Bury 8"	30.01	/mo	28ft Square Steel Direct Bury 8"	34.66	/mo	4.65	575
576					32ft Square Steel Direct Bury 8"	31.37	/mo	32ft Square Steel Direct Bury 8"	36.24	/mo	4.87	576
577					41ft6in Decorative Transit Direct Bury	21.60	/mo	41ft6in Decorative Transit Direct Bury	24.95	/mo	3.35	577
578					47ft Decorative Transit Direct Bury	26.91	/mo	47ft Decorative Transit Direct Bury	31.08	/mo	4.17	578
579					35ft Steel Distribution Pole	24.84	/mo	35ft Steel Distribution Pole	28.69	/mo	3.85	579
580						37.00	/mo		42.74	/mo	5.74	580
581					16ft Decorative Transit Anchor Post Top 23ft Gray Steel/Fiberglass Post Top	12.83	/mo	16ft Decorative Transit Anchor Post Top 23ft Gray Steel/Fiberglass Post Top	14.82	/mo	1.99	581
582					23ft Black Steel Post Top	14.14	/mo	23ft Black Steel Post Top	16.33	/mo	2.19	582
583								30ft Wood Pole	10.90	/mo	10.90	583
584								35ft Wood Pole	10.90	/mo	10.90	584
585								40ft Wood Pole	15.52	/mo	15.52	585
586												586
587					4ft Flush Anchor Base	$ 10.45	/mo	4ft Flush Anchor Base	$ 12.07	/mo	$ 1.62	587
588					6ft Flush Anchor Base	12.47	/mo	6ft Flush Anchor Base	14.40	/mo	1.93	588
589					8ft Pedestal Anchor Base	14.29	/mo	8ft Pedestal Anchor Base	16.51	/mo	2.22	589
590					4ft 6" Pedestal Anchor Base	9.91	/mo	4ft 6" Pedestal Anchor Base	11.45	/mo	1.54	590
591												591
592					100' OH, UG if conduit by customer	$ 3.69	/mo	100' OH, UG if conduit by customer	$ 4.26	/mo	$ 0.57	592
593												593
594					Non-Standard			Non-Standard				594
595					Service Charge	$ 3.54	/mo	Service Charge	$ 4.09	/mo	$ 0.55	595
596					All kWh	0.06857	/kWh	All kWh	0.07949	/kWh	0.01092	596

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) Change (I) - (F)	Line No.
597										597
598	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**FIXTURES (Company Owned)**		**FIXTURES (Company Owned)**			598
599		Service			3835 LED ACORN - Frozen	$ 21.19 /mo	3835 LED ACORN - Frozen	$ 24.48 /mo	$ 3.29	599
600					4796 LED Acorn - Frozen	17.02 /mo	4796 LED Acorn - Frozen	19.66 /mo	2.64	600
601					5003 LED Acorn - Frozen	22.97 /mo	5003 LED Acorn - Frozen	26.53 /mo	3.56	601
602					5904 LED Acorn - Frozen	22.56 /mo	5904 LED Acorn - Frozen	26.06 /mo	3.50	602
603					6000 IND Acorn - Frozen	18.85 /mo	6000 IND Acorn - Frozen	21.77 /mo	2.92	603
604					6200 IND Architectural - Frozen	9.92 /mo	6200 IND Architectural - Frozen	11.46 /mo	1.54	604
605					8400 IND Architectural - Frozen	10.47 /mo	8400 IND Architectural - Frozen	12.09 /mo	1.62	605
606					10200 IND Architectural - Frozen	11.51 /mo	10200 IND Architectural - Frozen	13.30 /mo	1.79	606
607					13000 IND Architectural - Frozen	12.71 /mo	13000 IND Architectural - Frozen	14.68 /mo	1.97	607
608					20500 IND Architectural - Frozen	14.48 /mo	20500 IND Architectural - Frozen	16.73 /mo	2.25	608
609					22500 IND Architectural - Frozen	17.27 /mo	22500 IND Architectural - Frozen	19.95 /mo	2.68	609
610					3300 LED Architectural - Frozen	10.03 /mo	3300 LED Architectural - Frozen	11.59 /mo	1.56	610
611					3800 LED Architectural - Frozen	7.57 /mo	3800 LED Architectural - Frozen	8.74 /mo	1.17	611
612					3900 LED Architectural - Frozen	9.76 /mo	3900 LED Architectural - Frozen	11.27 /mo	1.51	612
613					4050 LED Architectural - Frozen	18.25 /mo	4050 LED Architectural - Frozen	21.08 /mo	2.83	613
614					4100 LED Architectural - Frozen	10.13 /mo	4100 LED Architectural - Frozen	11.70 /mo	1.57	614
615					4800 LED Architectural - Frozen	8.10 /mo	4800 LED Architectural - Frozen	9.36 /mo	1.26	615
616					5000 LED Architectural - Frozen	9.41 /mo	5000 LED Architectural - Frozen	10.87 /mo	1.46	616
617					5100 LED Architectural - Frozen	9.97 /mo	5100 LED Architectural - Frozen	11.52 /mo	1.55	617
618					5300 LED Architectural - Frozen	10.26 /mo	5300 LED Architectural - Frozen	11.85 /mo	1.59	618
619					5800 LED Architectural - Frozen	17.44 /mo	5800 LED Architectural - Frozen	20.15 /mo	2.71	619
620					5890 LED Architectural - Frozen	20.14 /mo	5890 LED Architectural - Frozen	23.26 /mo	3.12	620
621					6000 LED Architectural - Frozen	18.25 /mo	6000 LED Architectural - Frozen	21.08 /mo	2.83	621
622					6000 LED Architectural - Frozen	19.48 /mo	6000 LED Architectural - Frozen	22.50 /mo	3.02	622
623					6810 LED Architectural - Frozen	18.50 /mo	6810 LED Architectural - Frozen	21.37 /mo	2.87	623
624					7100 LED Architectural - Frozen	19.30 /mo	7100 LED Architectural - Frozen	22.29 /mo	2.99	624
625					7400 LED Architectural - Frozen	20.00 /mo	7400 LED Architectural - Frozen	23.10 /mo	3.10	625
626					7500 LED Architectural - Frozen	19.67 /mo	7500 LED Architectural - Frozen	22.72 /mo	3.05	626
627					7700 LED Architectural - Frozen	18.03 /mo	7700 LED Architectural - Frozen	20.83 /mo	2.80	627
628					8200 LED Architectural - Frozen	10.24 /mo	8200 LED Architectural - Frozen	11.83 /mo	1.59	628
629					8200 LED Architectural - Frozen	11.63 /mo	8200 LED Architectural - Frozen	13.43 /mo	1.80	629
630					8300 LED Architectural - Frozen	17.56 /mo	8300 LED Architectural - Frozen	20.28 /mo	2.72	630
631					8300 LED Architectural - Frozen	12.19 /mo	8300 LED Architectural - Frozen	14.08 /mo	1.89	631
632					8500 LED Architectural - Frozen	11.45 /mo	8500 LED Architectural - Frozen	13.23 /mo	1.78	632
633					9020 LED Architectural - Frozen	22.47 /mo	9020 LED Architectural - Frozen	25.96 /mo	3.49	633
634					9900 LED Architectural - Frozen	13.54 /mo	9900 LED Architectural - Frozen	15.64 /mo	2.10	634
635					10000 LED Architectural - Frozen	20.99 /mo	10000 LED Architectural - Frozen	24.25 /mo	3.26	635
636					10000 LED Architectural - Frozen	12.99 /mo	10000 LED Architectural - Frozen	15.00 /mo	2.01	636
637					10600 LED Architectural - Frozen	22.10 /mo	10600 LED Architectural - Frozen	25.53 /mo	3.43	637
638					11100 LED Architectural - Frozen	12.50 /mo	11100 LED Architectural - Frozen	14.44 /mo	1.94	638
639					11500 LED Architectural - Frozen	12.89 /mo	11500 LED Architectural - Frozen	14.89 /mo	2.00	639
640					12300 LED Architectural - Frozen	24.96 /mo	12300 LED Architectural - Frozen	28.83 /mo	3.87	640
641					12900 LED Architectural - Frozen	21.85 /mo	12900 LED Architectural - Frozen	25.24 /mo	3.39	641
642					13260 LED Architectural - Frozen	26.55 /mo	13260 LED Architectural - Frozen	30.67 /mo	4.12	642
643					14000 LED Architectural - Frozen	25.54 /mo	14000 LED Architectural - Frozen	29.50 /mo	3.96	643
644					15000 LED Architectural - Frozen	24.42 /mo	15000 LED Architectural - Frozen	28.21 /mo	3.79	644
645					15400 LED Architectural - Frozen	24.69 /mo	15400 LED Architectural - Frozen	28.52 /mo	3.83	645
646					18300 LED Architectural - Frozen	15.80 /mo	18300 LED Architectural - Frozen	18.25 /mo	2.45	646
647					19200 LED Architectural - Frozen	26.32 /mo	19200 LED Architectural - Frozen	30.40 /mo	4.08	647
648					20000 LED Architectural - Frozen	26.32 /mo	20000 LED Architectural - Frozen	30.40 /mo	4.08	648
649					20300 LED Architectural - Frozen	16.82 /mo	20300 LED Architectural - Frozen	19.43 /mo	2.61	649
650					21000 LED Architectural - Frozen	24.26 /mo	21000 LED Architectural - Frozen	28.02 /mo	3.76	650

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) Change (I) - (F)	Line No.
651	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	6200 IND Cobra - Frozen	$ 10.32 /mo	6200 IND Cobra - Frozen	$ 11.92 /mo	$ 1.60	651
652	(continued)	Service			6400 IND Cobra - Frozen	8.79 /mo	6400 IND Cobra - Frozen	10.15 /mo	1.36	652
653					8000 IND Cobra - Frozen	10.26 /mo	8000 IND Cobra - Frozen	11.85 /mo	1.59	653
654					8400 IND Cobra - Frozen	9.50 /mo	8400 IND Cobra - Frozen	10.97 /mo	1.47	654
655					10200 IND Cobra - Frozen	10.23 /mo	10200 IND Cobra - Frozen	11.82 /mo	1.59	655
656					13000 IND Cobra - Frozen	11.26 /mo	13000 IND Cobra - Frozen	13.01 /mo	1.75	656
657					15250 IND Cobra - Frozen	13.58 /mo	15250 IND Cobra - Frozen	15.69 /mo	2.11	657
658					22500 IND Cobra - Frozen	18.17 /mo	22500 IND Cobra - Frozen	20.99 /mo	2.82	658
659					3500 IND Cobra Gray/Bronze - Frozen	10.28 /mo	3500 IND Cobra Gray/Bronze - Frozen	11.87 /mo	1.59	659
660					6000 LED Cobra - Frozen	16.70 /mo	6000 LED Cobra - Frozen	19.29 /mo	2.59	660
661					8700 LED Cobra - Frozen	18.78 /mo	8700 LED Cobra - Frozen	21.69 /mo	2.91	661
662					9600 LED Cobra - Frozen	19.98 /mo	9600 LED Cobra - Frozen	23.08 /mo	3.10	662
663					11600 LED-B Cobra - Frozen	18.64 /mo	11600 LED-B Cobra - Frozen	21.53 /mo	2.89	663
664					3300 LED Cobra Gray/Bronze - Frozen	8.82 /mo	3300 LED Cobra Gray/Bronze - Frozen	10.19 /mo	1.37	664
665					5300 LED Cobra Gray/Bronze - Frozen	10.24 /mo	5300 LED Cobra Gray/Bronze - Frozen	11.83 /mo	1.59	665
666					8300 LED Cobra Gray/Bronze - Frozen	13.27 /mo	8300 LED Cobra Gray/Bronze - Frozen	15.33 /mo	2.06	666
667					10500 LED Cobra Gray/Bronze - Frozen	14.77 /mo	10500 LED Cobra Gray/Bronze - Frozen	17.06 /mo	2.29	667
668					20000 LED Cobra Gray/Bronze - Frozen	25.67 /mo	20000 LED Cobra Gray/Bronze - Frozen	29.65 /mo	3.98	668
669					5300 LED Decorative Transit - Frozen	27.86 /mo	5300 LED Decorative Transit - Frozen	32.18 /mo	4.32	669
670					8300 LED Decorative Transit - Frozen	29.83 /mo	8300 LED Decorative Transit - Frozen	34.46 /mo	4.63	670
671					8147 LED Decorative Transit - Frozen	35.03 /mo	8147 LED Decorative Transit - Frozen	40.46 /mo	5.43	671
672					9522 LED Decorative Transit - Frozen	35.40 /mo	9522 LED Decorative Transit - Frozen	40.89 /mo	5.49	672
673					10500 LED Decorative Transit - Frozen	32.02 /mo	10500 LED Decorative Transit - Frozen	36.99 /mo	4.97	673
674					14896 LED Decorative Transit - Frozen	39.16 /mo	14896 LED Decorative Transit - Frozen	45.23 /mo	6.07	674
675					8147 LED Decorative Transit Double - Frozen	63.41 /mo	8147 LED Decorative Transit Double - Frozen	73.25 /mo	9.84	675
676					9522 LED Decorative Transit Double - Frozen	63.34 /mo	9522 LED Decorative Transit Double - Frozen	73.16 /mo	9.82	676
677					14896 LED Decorative Transit Double - Frozen	69.22 /mo	14896 LED Decorative Transit Double - Frozen	79.96 /mo	10.74	677
678					6000 IND Decorative Transit Copper - Frozen	18.48 /mo	6000 IND Decorative Transit Copper - Frozen	21.35 /mo	2.87	678
679					8000 IND Decorative Transit Gray/Black - Frozen	14.56 /mo	8000 IND Decorative Transit Gray/Black - Frozen	16.82 /mo	2.26	679
680					4350 LED Decorative Transit Gray/Black - Frozen	13.20 /mo	4350 LED Decorative Transit Gray/Black - Frozen	15.25 /mo	2.05	680
681					14470 LED Flood - Frozen	23.44 /mo	14470 LED Flood - Frozen	27.08 /mo	3.64	681
682					16000 LED Flood - Frozen	22.70 /mo	16000 LED Flood - Frozen	26.22 /mo	3.52	682
683					8678 LED Pendant - Frozen	25.82 /mo	8678 LED Pendant - Frozen	29.82 /mo	4.00	683
684					13964 LED Pendant - Frozen	27.27 /mo	13964 LED Pendant - Frozen	31.50 /mo	4.23	684
685					4350 LED Post Top - Frozen	13.15 /mo	4350 LED Post Top - Frozen	15.19 /mo	2.04	685
686					6400 LED Post Top - Frozen	13.15 /mo	6400 LED Post Top - Frozen	15.19 /mo	2.04	686
687					6600 LED Post Top - Frozen	13.06 /mo	6600 LED Post Top - Frozen	15.09 /mo	2.03	687
688					3300 LED Roadway - Frozen	9.27 /mo	3300 LED Roadway - Frozen	10.71 /mo	1.44	688
689					3800 LED Roadway - Frozen	7.09 /mo	3800 LED Roadway - Frozen	8.19 /mo	1.10	689
690					3900 LED Roadway - Frozen	8.99 /mo	3900 LED Roadway - Frozen	10.38 /mo	1.39	690
691					4100 LED Roadway - Frozen	9.36 /mo	4100 LED Roadway - Frozen	10.81 /mo	1.45	691
692					4800 LED Roadway - Frozen	7.60 /mo	4800 LED Roadway - Frozen	8.78 /mo	1.18	692
693					5000 LED Roadway - Frozen	8.93 /mo	5000 LED Roadway - Frozen	10.32 /mo	1.39	693
694					5100 LED Roadway - Frozen	9.49 /mo	5100 LED Roadway - Frozen	10.96 /mo	1.47	694
695					5300 LED Roadway - Frozen	9.78 /mo	5300 LED Roadway - Frozen	11.30 /mo	1.52	695
696					8200 LED Roadway - Frozen	9.52 /mo	8200 LED Roadway - Frozen	11.00 /mo	1.48	696
697					8200 LED Roadway - Frozen	11.13 /mo	8200 LED Roadway - Frozen	12.86 /mo	1.73	697
698					8300 LED Roadway - Frozen	11.50 /mo	8300 LED Roadway - Frozen	13.28 /mo	1.78	698

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
699	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	8500 LED Roadway - Frozen	$ 10.95	/mo	8500 LED Roadway - Frozen	$ 12.65	/mo	$ 1.70	699
700	(continued)	Service			9900 LED Roadway - Frozen	13.04	/mo	9900 LED Roadway - Frozen	15.06	/mo	2.02	700
701					10000 LED Roadway - Frozen	12.49	/mo	10000 LED Roadway - Frozen	14.43	/mo	1.94	701
702					11100 LED Roadway - Frozen	11.78	/mo	11100 LED Roadway - Frozen	13.61	/mo	1.83	702
703					11500 LED Roadway - Frozen	12.39	/mo	11500 LED Roadway - Frozen	14.31	/mo	1.92	703
704					18300 LED Roadway - Frozen	14.92	/mo	18300 LED Roadway - Frozen	17.23	/mo	2.31	704
705					19200 LED Roadway - Frozen	18.72	/mo	19200 LED Roadway - Frozen	21.62	/mo	2.90	705
706					20000 LED Roadway - Frozen	18.72	/mo	20000 LED Roadway - Frozen	21.62	/mo	2.90	706
707					20300 LED Roadway - Frozen	15.94	/mo	20300 LED Roadway - Frozen	18.41	/mo	2.47	707
708					21000 LED Roadway - Frozen	16.66	/mo	21000 LED Roadway - Frozen	19.24	/mo	2.58	708
709					4000 Inc Acorn- Frozen	10.32	/mo	4000 Inc Acorn- Frozen	11.92	/mo	1.60	709
710					7000 Mv Acorn- Frozen	7.67	/mo	7000 Mv Acorn- Frozen	8.86	/mo	1.19	710
711					20000 Mv Acorn- Frozen	26.29	/mo	20000 Mv Acorn- Frozen	30.37	/mo	4.08	711
712					9500 HPS Acorn- Frozen	28.54	/mo	9500 HPS Acorn- Frozen	32.97	/mo	4.43	712
713					16000 HPS Acorn- Frozen	31.69	/mo	16000 HPS Acorn- Frozen	36.61	/mo	4.92	713
714					9500 HPS Architectural - Frozen	16.22	/mo	9500 HPS Architectural - Frozen	18.74	/mo	2.52	714
715					16000 HPS Architectural - Frozen	18.94	/mo	16000 HPS Architectural - Frozen	21.88	/mo	2.94	715
716					30000 HPS Architectural - Frozen	22.48	/mo	30000 HPS Architectural - Frozen	25.97	/mo	3.49	716
717					50000 HPS Architectural - Frozen	27.74	/mo	50000 HPS Architectural - Frozen	32.04	/mo	4.30	717
718					14000 MH Architectural - Frozen	22.70	/mo	14000 MH Architectural - Frozen	26.22	/mo	3.52	718
719					21000 MH Architectural - Frozen	25.77	/mo	21000 MH Architectural - Frozen	29.77	/mo	4.00	719
720					36000 MH Architectural - Frozen	32.22	/mo	36000 MH Architectural - Frozen	37.22	/mo	5.00	720
721					8000 LPS Architectural - Frozen	23.59	/mo	8000 LPS Architectural - Frozen	27.25	/mo	3.66	721
722					13500 LPS Architectural - Frozen	27.81	/mo	13500 LPS Architectural - Frozen	32.12	/mo	4.31	722
723					22500 LPS Architectural - Frozen	31.77	/mo	22500 LPS Architectural - Frozen	36.70	/mo	4.93	723
724					33000 LPS Architectural - Frozen	38.21	/mo	33000 LPS Architectural - Frozen	44.14	/mo	5.93	724
725					5800 HPS Cobra/Roadway - Frozen	9.21	/mo	5800 HPS Cobra/Roadway - Frozen	10.64	/mo	1.43	725
726					9500 HPS Cobra/Roadway - Frozen	10.84	/mo	9500 HPS Cobra/Roadway - Frozen	12.52	/mo	1.68	726
727					16000 HPS Cobra/Roadway - Frozen	13.58	/mo	16000 HPS Cobra/Roadway - Frozen	15.69	/mo	2.11	727
728					30000 HPS Cobra/Roadway - Frozen	16.38	/mo	30000 HPS Cobra/Roadway - Frozen	18.92	/mo	2.54	728
729					50000 HPS Cobra/Roadway - Frozen	22.22	/mo	50000 HPS Cobra/Roadway - Frozen	25.67	/mo	3.45	729
730					14000 MH Cobra/Roadway - Frozen	15.79	/mo	14000 MH Cobra/Roadway - Frozen	18.24	/mo	2.45	730
731					21000 MH Cobra/Roadway - Frozen	18.45	/mo	21000 MH Cobra/Roadway - Frozen	21.31	/mo	2.86	731
732					36000 MH Cobra/Roadway - Frozen	24.30	/mo	36000 MH Cobra/Roadway - Frozen	28.07	/mo	3.77	732
733					8000 FL Cobra/Roadway - Frozen	18.15	/mo	8000 FL Cobra/Roadway - Frozen	20.97	/mo	2.82	733
734					9500 HPS Decorative Transit - Frozen	39.13	/mo	9500 HPS Decorative Transit - Frozen	45.20	/mo	6.07	734
735					16000 HPS Decorative Transit - Frozen	38.91	/mo	16000 HPS Decorative Transit - Frozen	44.95	/mo	6.04	735
736					30000 HPS Decorative Transit - Frozen	44.80	/mo	30000 HPS Decorative Transit - Frozen	51.75	/mo	6.95	736
737					30000 HPS Flood - Frozen	21.74	/mo	30000 HPS Flood - Frozen	25.11	/mo	3.37	737
738					50000 HPS Flood - Frozen	26.97	/mo	50000 HPS Flood - Frozen	31.15	/mo	4.18	738
739					21000 MH Flood - Frozen	23.20	/mo	21000 MH Flood - Frozen	26.80	/mo	3.60	739
740					36000 MH Flood - Frozen	28.30	/mo	36000 MH Flood - Frozen	32.69	/mo	4.39	740
741					8000 FL Post Top - Frozen	19.56	/mo	8000 FL Post Top - Frozen	22.59	/mo	3.03	741
742					9500 HPS Post Top Colonial Gray- Frozen	11.19	/mo	9500 HPS Post Top Colonial Gray- Frozen	12.93	/mo	1.74	742
743					9500 HPS Post Top Colonial Black- Frozen	12.88	/mo	9500 HPS Post Top Colonial Black- Frozen	14.88	/mo	2.00	743
744					9500 HPS Decorative Post Top - Frozen	34.25	/mo	9500 HPS Decorative Post Top - Frozen	39.56	/mo	5.31	744
745					Brackets over 8 ft. and up to 16 ft. in length - Frozen	1.81	/mo	Brackets over 8 ft. and up to 16 ft. in length - Frozen	2.09	/mo	0.28	745
746					4300 LED Architectural Roadway Bronze - Frozen	10.34	/mo	4300 LED Architectural Roadway Bronze - Frozen	11.94	/mo	1.60	746
747					20100 LED Architectural Roadway Bronze - Frozen	16.51	/mo	20100 LED Architectural Roadway Bronze - Frozen	19.07	/mo	2.56	747

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
748	E-47 (continued)	Dusk to Dawn Lighting Service	Rate	Sum & Win	21000 LED Architectural Roadway Bronze - Frozen	$ 24.11	/mo	21000 LED Architectural Roadway Bronze - Frozen	$ 27.85	/mo	$ 3.74	748
749					20100 LED Cobra Gray - Frozen	15.61	/mo	20100 LED Cobra Gray - Frozen	18.03	/mo	2.42	749
750					21000 LED Cobra Gray - Frozen	16.35	/mo	21000 LED Cobra Gray - Frozen	18.89	/mo	2.54	750
751					4300 LED Roadway Gray - Frozen	9.79	/mo	4300 LED Roadway Gray - Frozen	11.31	/mo	1.52	751
752					5400 LED Roadway Gray - Frozen	9.69	/mo	5400 LED Roadway Gray - Frozen	11.19	/mo	1.50	752
753					8600 LED Roadway Gray - Frozen	11.36	/mo	8600 LED Roadway Gray - Frozen	13.12	/mo	1.76	753
754					6400 LED Post Top/Salem Black - Frozen	12.49	/mo	6400 LED Post Top/Salem Black - Frozen	14.43	/mo	1.94	754
755					4350 LED Post Top/Salem Black - Frozen	12.59	/mo	4350 LED Post Top/Salem Black - Frozen	14.54	/mo	1.95	755
756					5600 LED Town & Country/Gray - Frozen	9.16	/mo	5600 LED Town & Country/Gray - Frozen	10.58	/mo	1.42	756
757					5600 LED Town & Country/Black - Frozen	9.16	/mo	5600 LED Town & Country/Black - Frozen	10.58	/mo	1.42	757
758					3720 LED Decorative Transit/Single - Frozen	38.81	/mo	3720 LED Decorative Transit/Single - Frozen	44.83	/mo	6.02	758
759					3408 LED Roadway Architectural Bronze - Frozen	8.38	/mo	3408 LED Roadway Architectural Bronze - Frozen	9.68	/mo	1.30	759
760					4800 LED Roadway Architectural Bronze - Frozen	8.76	/mo	4800 LED Roadway Architectural Bronze - Frozen	10.12	/mo	1.36	760
761					4900 LED Roadway Architectural Bronze - Frozen	8.61	/mo	4900 LED Roadway Architectural Bronze - Frozen	9.95	/mo	1.34	761
762					7810 LED Roadway Architectural Bronze - Frozen	11.21	/mo	7810 LED Roadway Architectural Bronze - Frozen	12.95	/mo	1.74	762
763					8165 LED Roadway Architectural Bronze - Frozen	11.20	/mo	8165 LED Roadway Architectural Bronze - Frozen	12.94	/mo	1.74	763
764					11000 LED Roadway Architectural Bronze - Frozen	12.19	/mo	11000 LED Roadway Architectural Bronze - Frozen	14.08	/mo	1.89	764
765					11500 LED Roadway Architectural Bronze - Frozen	12.15	/mo	11500 LED Roadway Architectural Bronze - Frozen	14.03	/mo	1.88	765
766					3408 LED Cobra Roadway Gray - Frozen	7.75	/mo	3408 LED Cobra Roadway Gray - Frozen	8.95	/mo	1.20	766
767					4800 LED Cobra Roadway Gray - Frozen	8.13	/mo	4800 LED Cobra Roadway Gray - Frozen	9.39	/mo	1.26	767
768					4900 LED Cobra Roadway Gray - Frozen	8.18	/mo	4900 LED Cobra Roadway Gray - Frozen	9.45	/mo	1.27	768
769					7810 LED Cobra Roadway Gray - Frozen	10.41	/mo	7810 LED Cobra Roadway Gray - Frozen	12.02	/mo	1.61	769
770					8165 LED Cobra Roadway Gray - Frozen	10.60	/mo	8165 LED Cobra Roadway Gray - Frozen	12.24	/mo	1.64	770
771					11000 LED Cobra Roadway Gray - Frozen	11.39	/mo	11000 LED Cobra Roadway Gray - Frozen	13.16	/mo	1.77	771
772					11500 LED Cobra Roadway Gray - Frozen	11.29	/mo	11500 LED Cobra Roadway Gray - Frozen	13.04	/mo	1.75	772
773					14500 LED Flood - Frozen	14.71	/mo	14500 LED Flood - Frozen	16.99	/mo	2.28	773
774					**FIXTURES (Customer Owned)**			**FIXTURES (Customer Owned)**				774
775					3835 LED Acorn - Frozen	$ 2.68	/mo	3835 LED Acorn - Frozen	$ 3.10	/mo	$ 0.42	775
776					4796 LED Acorn - Frozen	2.63	/mo	4796 LED Acorn - Frozen	3.04	/mo	0.41	776
777					5003 LED Acorn - Frozen	3.54	/mo	5003 LED Acorn - Frozen	4.09	/mo	0.55	777
778					5904 LED Acorn - Frozen	3.54	/mo	5904 LED Acorn - Frozen	4.09	/mo	0.55	778
779					6000 IND Acorn - Frozen	2.92	/mo	6000 IND Acorn - Frozen	3.37	/mo	0.45	779
780					6200 IND Architectural - Frozen	2.92	/mo	6200 IND Architectural - Frozen	3.37	/mo	0.45	780
781					8400 IND Architectural - Frozen	3.32	/mo	8400 IND Architectural - Frozen	3.84	/mo	0.52	781
782					10200 IND Architectural - Frozen	3.87	/mo	10200 IND Architectural - Frozen	4.47	/mo	0.60	782
783					13000 IND Architectural - Frozen	4.74	/mo	13000 IND Architectural - Frozen	5.48	/mo	0.74	783

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) Change (I) - (F)	Line No.
784	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	20500 IND Architectural - Frozen	$ 6.10 /mo	20500 IND Architectural - Frozen	$ 7.05 /mo	$ 0.95	784
785	(continued)	Service			22500 IND Architectural - Frozen	7.85 /mo	22500 IND Architectural - Frozen	9.07 /mo	1.22	785
786					3300 LED Architectural - Frozen	1.53 /mo	3300 LED Architectural - Frozen	1.77 /mo	0.24	786
787					3800 LED Architectural - Frozen	1.22 /mo	3800 LED Architectural - Frozen	1.41 /mo	0.19	787
788					3900 LED Architectural - Frozen	1.25 /mo	3900 LED Architectural - Frozen	1.44 /mo	0.19	788
789					4050 LED Architectural - Frozen	2.28 /mo	4050 LED Architectural - Frozen	2.63 /mo	0.35	789
790					4100 LED Architectural - Frozen	1.63 /mo	4100 LED Architectural - Frozen	1.88 /mo	0.25	790
791					4800 LED Architectural - Frozen	1.51 /mo	4800 LED Architectural - Frozen	1.74 /mo	0.23	791
792					5000 LED Architectural - Frozen	1.52 /mo	5000 LED Architectural - Frozen	1.76 /mo	0.24	792
793					5100 LED Architectural - Frozen	2.08 /mo	5100 LED Architectural - Frozen	2.40 /mo	0.32	793
794					5300 LED Architectural - Frozen	2.36 /mo	5300 LED Architectural - Frozen	2.73 /mo	0.37	794
795					5800 LED Architectural - Frozen	3.16 /mo	5800 LED Architectural - Frozen	3.65 /mo	0.49	795
796					5890 LED Architectural - Frozen	3.13 /mo	5890 LED Architectural - Frozen	3.62 /mo	0.49	796
797					6000 LED Architectural - Frozen	2.28 /mo	6000 LED Architectural - Frozen	2.63 /mo	0.35	797
798					6000 LED Architectural - Frozen	2.48 /mo	6000 LED Architectural - Frozen	2.86 /mo	0.38	798
799					6810 LED Architectural - Frozen	3.49 /mo	6810 LED Architectural - Frozen	4.03 /mo	0.54	799
800					7100 LED Architectural - Frozen	2.29 /mo	7100 LED Architectural - Frozen	2.65 /mo	0.36	800
801					7400 LED Architectural - Frozen	4.11 /mo	7400 LED Architectural - Frozen	4.75 /mo	0.64	801
802					7500 LED Architectural - Frozen	2.66 /mo	7500 LED Architectural - Frozen	3.07 /mo	0.41	802
803					7700 LED Architectural - Frozen	3.02 /mo	7700 LED Architectural - Frozen	3.49 /mo	0.47	803
804					8200 LED Architectural - Frozen	3.01 /mo	8200 LED Architectural - Frozen	3.48 /mo	0.47	804
805					8200 LED Architectural - Frozen	3.20 /mo	8200 LED Architectural - Frozen	3.70 /mo	0.50	805
806					8300 LED Architectural - Frozen	2.55 /mo	8300 LED Architectural - Frozen	2.95 /mo	0.40	806
807					8300 LED Architectural - Frozen	3.58 /mo	8300 LED Architectural - Frozen	4.14 /mo	0.56	807
808					8500 LED Architectural - Frozen	3.03 /mo	8500 LED Architectural - Frozen	3.50 /mo	0.47	808
809					9020 LED Architectural - Frozen	4.71 /mo	9020 LED Architectural - Frozen	5.44 /mo	0.73	809
810					9900 LED Architectural - Frozen	4.33 /mo	9900 LED Architectural - Frozen	5.00 /mo	0.67	810
811					10000 LED Architectural - Frozen	3.23 /mo	10000 LED Architectural - Frozen	3.73 /mo	0.50	811
812					10000 LED Architectural - Frozen	3.78 /mo	10000 LED Architectural - Frozen	4.37 /mo	0.59	812
813					10600 LED Architectural - Frozen	4.34 /mo	10600 LED Architectural - Frozen	5.01 /mo	0.67	813
814					11100 LED Architectural - Frozen	3.67 /mo	11100 LED Architectural - Frozen	4.24 /mo	0.57	814
815					11500 LED Architectural - Frozen	3.68 /mo	11500 LED Architectural - Frozen	4.25 /mo	0.57	815
816					12300 LED Architectural - Frozen	6.18 /mo	12300 LED Architectural - Frozen	7.14 /mo	0.96	816
817					12900 LED Architectural - Frozen	4.06 /mo	12900 LED Architectural - Frozen	4.69 /mo	0.63	817
818					13260 LED Architectural - Frozen	6.80 /mo	13260 LED Architectural - Frozen	7.85 /mo	1.05	818
819					14000 LED Architectural - Frozen	5.78 /mo	14000 LED Architectural - Frozen	6.68 /mo	0.90	819
820					15000 LED Architectural - Frozen	4.66 /mo	15000 LED Architectural - Frozen	5.38 /mo	0.72	820
821					15400 LED Architectural - Frozen	4.94 /mo	15400 LED Architectural - Frozen	5.71 /mo	0.77	821
822					18300 LED Architectural - Frozen	5.38 /mo	18300 LED Architectural - Frozen	6.21 /mo	0.83	822
823					19200 LED Architectural - Frozen	8.54 /mo	19200 LED Architectural - Frozen	9.86 /mo	1.32	823
824					20000 LED Architectural - Frozen	8.54 /mo	20000 LED Architectural - Frozen	9.86 /mo	1.32	824
825					20300 LED Architectural - Frozen	6.40 /mo	20300 LED Architectural - Frozen	7.39 /mo	0.99	825
826					21000 LED Architectural - Frozen	6.48 /mo	21000 LED Architectural - Frozen	7.49 /mo	1.01	826
827					6200 IND Cobra - Frozen	2.68 /mo	6200 IND Cobra - Frozen	3.10 /mo	0.42	827
828					6400 IND Cobra - Frozen	2.92 /mo	6400 IND Cobra - Frozen	3.37 /mo	0.45	828
829					8000 IND Cobra - Frozen	3.00 /mo	8000 IND Cobra - Frozen	3.47 /mo	0.47	829
830					8400 IND Cobra - Frozen	3.32 /mo	8400 IND Cobra - Frozen	3.84 /mo	0.52	830
831					10200 IND Cobra - Frozen	3.87 /mo	10200 IND Cobra - Frozen	4.47 /mo	0.60	831
832					13000 IND Cobra - Frozen	4.74 /mo	13000 IND Cobra - Frozen	5.48 /mo	0.74	832
833					15250 IND Cobra - Frozen	6.10 /mo	15250 IND Cobra - Frozen	7.05 /mo	0.95	833
834					22500 IND Cobra - Frozen	7.44 /mo	22500 IND Cobra - Frozen	8.59 /mo	1.15	834
835					3500 IND Cobra Gray/Bronze - Frozen	2.12 /mo	3500 IND Cobra Gray/Bronze - Frozen	2.45 /mo	0.33	835
836					6000 LED Cobra - Frozen	3.24 /mo	6000 LED Cobra - Frozen	3.74 /mo	0.50	836

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
837	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	8700 LED Cobra - Frozen	$ 4.51	/mo	8700 LED Cobra - Frozen	$ 5.21	/mo	$ 0.70	837
838	(continued)	Service			9600 LED Cobra - Frozen	4.91	/mo	9600 LED Cobra - Frozen	5.67	/mo	0.76	838
839					11600 LED-B Cobra - Frozen	5.53	/mo	11600 LED-B Cobra - Frozen	6.39	/mo	0.86	839
840					3300 LED Cobra Gray/Bronze - Frozen	1.80	/mo	3300 LED Cobra Gray/Bronze - Frozen	2.08	/mo	0.28	840
841					5300 LED Cobra Gray/Bronze - Frozen	2.44	/mo	5300 LED Cobra Gray/Bronze - Frozen	2.82	/mo	0.38	841
842					8300 LED Cobra Gray/Bronze - Frozen	3.56	/mo	8300 LED Cobra Gray/Bronze - Frozen	4.11	/mo	0.55	842
843					10500 LED Cobra Gray/Bronze - Frozen	4.19	/mo	10500 LED Cobra Gray/Bronze - Frozen	4.84	/mo	0.65	843
844					20000 LED Cobra Gray/Bronze - Frozen	7.70	/mo	20000 LED Cobra Gray/Bronze - Frozen	8.89	/mo	1.19	844
845					5300 LED Decorative Transit - Frozen	2.68	/mo	5300 LED Decorative Transit - Frozen	3.10	/mo	0.42	845
846					8300 LED Decorative Transit - Frozen	3.32	/mo	8300 LED Decorative Transit - Frozen	3.84	/mo	0.52	846
847					8147 LED Decorative Transit - Frozen	2.86	/mo	8147 LED Decorative Transit - Frozen	3.30	/mo	0.44	847
848					9522 LED Decorative Transit - Frozen	3.69	/mo	9522 LED Decorative Transit - Frozen	4.26	/mo	0.57	848
849					10500 LED Decorative Transit - Frozen	4.74	/mo	10500 LED Decorative Transit - Frozen	5.48	/mo	0.74	849
850					14896 LED Decorative Transit - Frozen	5.30	/mo	14896 LED Decorative Transit - Frozen	6.12	/mo	0.82	850
851					8147 LED Decorative Transit Double - Frozen	3.06	/mo	8147 LED Decorative Transit Double - Frozen	3.53	/mo	0.47	851
852					9522 LED Decorative Transit Double - Frozen	3.90	/mo	9522 LED Decorative Transit Double - Frozen	4.51	/mo	0.61	852
853					14896 LED Decorative Transit Double - Frozen	5.48	/mo	14896 LED Decorative Transit Double - Frozen	6.33	/mo	0.85	853
854					6000 IND Decorative Transit Copper - Frozen	2.92	/mo	6000 IND Decorative Transit Copper - Frozen	3.37	/mo	0.45	854
855					8000 IND Decorative Transit Gray/Black - Frozen	3.00	/mo	8000 IND Decorative Transit Gray/Black - Frozen	3.47	/mo	0.47	855
856					4350 LED Decorative Transit Gray/Black - Frozen	3.00	/mo	4350 LED Decorative Transit Gray/Black - Frozen	3.47	/mo	0.47	856
857					14470 LED Flood - Frozen	5.02	/mo	14470 LED Flood - Frozen	5.80	/mo	0.78	857
858					16000 LED Flood - Frozen	4.27	/mo	16000 LED Flood - Frozen	4.93	/mo	0.66	858
859					8678 LED Pendant - Frozen	2.74	/mo	8678 LED Pendant - Frozen	3.17	/mo	0.43	859
860					13964 LED Pendant - Frozen	3.59	/mo	13964 LED Pendant - Frozen	4.15	/mo	0.56	860
861					4350 LED Post Top - Frozen	2.95	/mo	4350 LED Post Top - Frozen	3.41	/mo	0.46	861
862					6400 LED Post Top - Frozen	2.95	/mo	6400 LED Post Top - Frozen	3.41	/mo	0.46	862
863					6600 LED Post Top - Frozen	2.85	/mo	6600 LED Post Top - Frozen	3.29	/mo	0.44	863
864					3300 LED Roadway - Frozen	1.52	/mo	3300 LED Roadway - Frozen	1.76	/mo	0.24	864
865					3800 LED Roadway - Frozen	1.22	/mo	3800 LED Roadway - Frozen	1.41	/mo	0.19	865
866					3900 LED Roadway - Frozen	1.24	/mo	3900 LED Roadway - Frozen	1.43	/mo	0.19	866
867					4100 LED Roadway - Frozen	1.62	/mo	4100 LED Roadway - Frozen	1.87	/mo	0.25	867
868					4800 LED Roadway - Frozen	1.50	/mo	4800 LED Roadway - Frozen	1.73	/mo	0.23	868
869					5000 LED Roadway - Frozen	1.52	/mo	5000 LED Roadway - Frozen	1.76	/mo	0.24	869
870					5100 LED Roadway - Frozen	2.08	/mo	5100 LED Roadway - Frozen	2.40	/mo	0.32	870
871					5300 LED Roadway - Frozen	2.36	/mo	5300 LED Roadway - Frozen	2.73	/mo	0.37	871
872					8200 LED Roadway - Frozen	3.00	/mo	8200 LED Roadway - Frozen	3.47	/mo	0.47	872
873					8200 LED Roadway - Frozen	3.19	/mo	8200 LED Roadway - Frozen	3.69	/mo	0.50	873
874					8300 LED Roadway - Frozen	3.57	/mo	8300 LED Roadway - Frozen	4.12	/mo	0.55	874
875					8500 LED Roadway - Frozen	3.02	/mo	8500 LED Roadway - Frozen	3.49	/mo	0.47	875
876					9900 LED Roadway - Frozen	4.32	/mo	9900 LED Roadway - Frozen	4.99	/mo	0.67	876
877					10000 LED Roadway - Frozen	3.77	/mo	10000 LED Roadway - Frozen	4.35	/mo	0.58	877
878					11100 LED Roadway - Frozen	3.67	/mo	11100 LED Roadway - Frozen	4.24	/mo	0.57	878
879					11500 LED Roadway - Frozen	3.67	/mo	11500 LED Roadway - Frozen	4.24	/mo	0.57	879
880					18300 LED Roadway - Frozen	5.36	/mo	18300 LED Roadway - Frozen	6.19	/mo	0.83	880
881					19200 LED Roadway - Frozen	8.44	/mo	19200 LED Roadway - Frozen	9.75	/mo	1.31	881
882					20000 LED Roadway - Frozen	8.44	/mo	20000 LED Roadway - Frozen	9.75	/mo	1.31	882
883					20300 LED Roadway - Frozen	6.38	/mo	20300 LED Roadway - Frozen	7.37	/mo	0.99	883
884					21000 LED Roadway - Frozen	6.39	/mo	21000 LED Roadway - Frozen	7.38	/mo	0.99	884

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
885	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	4000 Inc Acorn- Frozen	$ 5.77	/mo	4000 Inc Acorn- Frozen	$ 6.67	/mo	$ 0.90	885
886	(continued)	Service			7000 Mv Acorn- Frozen	13.37	/mo	7000 Mv Acorn- Frozen	15.44	/mo	2.07	886
887					20000 Mv Acorn- Frozen	14.90	/mo	20000 Mv Acorn- Frozen	17.21	/mo	2.31	887
888					9500 HPS Acorn- Frozen	9.73	/mo	9500 HPS Acorn- Frozen	11.24	/mo	1.51	888
889					16000 HPS Acorn- Frozen	12.29	/mo	16000 HPS Acorn- Frozen	14.20	/mo	1.91	889
890					9500 HPS Architectural - Frozen	7.53	/mo	9500 HPS Architectural - Frozen	8.70	/mo	1.17	890
891					16000 HPS Architectural - Frozen	10.36	/mo	16000 HPS Architectural - Frozen	11.97	/mo	1.61	891
892					30000 HPS Architectural - Frozen	13.29	/mo	30000 HPS Architectural - Frozen	15.35	/mo	2.06	892
893					50000 HPS Architectural - Frozen	19.13	/mo	50000 HPS Architectural - Frozen	22.10	/mo	2.97	893
894					14000 MH Architectural - Frozen	12.44	/mo	14000 MH Architectural - Frozen	14.37	/mo	1.93	894
895					21000 MH Architectural - Frozen	15.34	/mo	21000 MH Architectural - Frozen	17.72	/mo	2.38	895
896					36000 MH Architectural - Frozen	21.10	/mo	36000 MH Architectural - Frozen	24.37	/mo	3.27	896
897					8000 LPS Architectural - Frozen	10.36	/mo	8000 LPS Architectural - Frozen	11.97	/mo	1.61	897
898					13500 LPS Architectural - Frozen	12.50	/mo	13500 LPS Architectural - Frozen	14.44	/mo	1.94	898
899					22500 LPS Architectural - Frozen	15.24	/mo	22500 LPS Architectural - Frozen	17.60	/mo	2.36	899
900					33000 LPS Architectural - Frozen	17.95	/mo	33000 LPS Architectural - Frozen	20.73	/mo	2.78	900
901					5800 HPS Cobra/Roadway - Frozen	5.45	/mo	5800 HPS Cobra/Roadway - Frozen	6.30	/mo	0.85	901
902					9500 HPS Cobra/Roadway - Frozen	6.67	/mo	9500 HPS Cobra/Roadway - Frozen	7.70	/mo	1.03	902
903					16000 HPS Cobra/Roadway - Frozen	9.31	/mo	16000 HPS Cobra/Roadway - Frozen	10.75	/mo	1.44	903
904					30000 HPS Cobra/Roadway - Frozen	12.10	/mo	30000 HPS Cobra/Roadway - Frozen	13.98	/mo	1.88	904
905					50000 HPS Cobra/Roadway - Frozen	17.27	/mo	50000 HPS Cobra/Roadway - Frozen	19.95	/mo	2.68	905
906					14000 MH Cobra/Roadway - Frozen	10.76	/mo	14000 MH Cobra/Roadway - Frozen	12.43	/mo	1.67	906
907					21000 MH Cobra/Roadway - Frozen	13.39	/mo	21000 MH Cobra/Roadway - Frozen	15.47	/mo	2.08	907
908					36000 MH Cobra/Roadway - Frozen	18.60	/mo	36000 MH Cobra/Roadway - Frozen	21.49	/mo	2.89	908
909					8000 FL Cobra/Roadway - Frozen	5.32	/mo	8000 FL Cobra/Roadway - Frozen	6.15	/mo	0.83	909
910					9500 HPS Decorative Transit - Frozen	11.71	/mo	9500 HPS Decorative Transit - Frozen	13.53	/mo	1.82	910
911					16000 HPS Decorative Transit - Frozen	6.66	/mo	16000 HPS Decorative Transit - Frozen	7.69	/mo	1.03	911
912					30000 HPS Decorative Transit - Frozen	16.91	/mo	30000 HPS Decorative Transit - Frozen	19.53	/mo	2.62	912
913					30000 HPS Flood - Frozen	13.51	/mo	30000 HPS Flood - Frozen	15.61	/mo	2.10	913
914					50000 HPS Flood - Frozen	18.75	/mo	50000 HPS Flood - Frozen	21.66	/mo	2.91	914
915					21000 MH Flood - Frozen	14.28	/mo	21000 MH Flood - Frozen	16.50	/mo	2.22	915
916					36000 MH Flood - Frozen	19.35	/mo	36000 MH Flood - Frozen	22.35	/mo	3.00	916
917					8000 FL Post Top - Frozen	5.52	/mo	8000 FL Post Top - Frozen	6.38	/mo	0.86	917
918					9500 HPS Post Top Colonial Gray- Frozen	7.01	/mo	9500 HPS Post Top Colonial Gray- Frozen	8.10	/mo	1.09	918
919					9500 HPS Post Top Colonial Black- Frozen	7.26	/mo	9500 HPS Post Top Colonial Black- Frozen	8.39	/mo	1.13	919
920					9500 HPS Decorative Post Top - Frozen	10.80	/mo	9500 HPS Decorative Post Top - Frozen	12.48	/mo	1.68	920
921					4300 LED Architectural Roadway Bronze - Frozen	1.66	/mo	4300 LED Architectural Roadway Bronze - Frozen	1.92	/mo	0.26	921
922					20100 LED Architectural Roadway Bronze - Frozen	5.87	/mo	20100 LED Architectural Roadway Bronze - Frozen	6.78	/mo	0.91	922
923					21000 LED Architectural Roadway Bronze - Frozen	5.96	/mo	21000 LED Architectural Roadway Bronze - Frozen	6.88	/mo	0.92	923
924					20100 LED Cobra Gray - Frozen	5.85	/mo	20100 LED Cobra Gray - Frozen	6.76	/mo	0.91	924
925					21000 LED Cobra Gray - Frozen	5.86	/mo	21000 LED Cobra Gray - Frozen	6.77	/mo	0.91	925
926					4300 LED Roadway Gray - Frozen	1.65	/mo	4300 LED Roadway Gray - Frozen	1.91	/mo	0.26	926
927					5400 LED Roadway Gray - Frozen	2.12	/mo	5400 LED Roadway Gray - Frozen	2.45	/mo	0.33	927
928					8600 LED Roadway Gray - Frozen	3.26	/mo	8600 LED Roadway Gray - Frozen	3.77	/mo	0.51	928
929					6400 LED Post Top/Salem Black - Frozen	2.90	/mo	6400 LED Post Top/Salem Black - Frozen	3.35	/mo	0.45	929
930					4350 LED Post Top/Salem Black - Frozen	3.00	/mo	4350 LED Post Top/Salem Black - Frozen	3.47	/mo	0.47	930

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
931	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	5600 LED Town & Country/Gray - Frozen	$ 2.02	/mo	5600 LED Town & Country/Gray - Frozen	$ 2.33	/mo	$ 0.31	931
932	(continued)	Service			5600 LED Town & Country/Black - Frozen	2.02	/mo	5600 LED Town & Country/Black - Frozen	2.33	/mo	0.31	932
933					3720 LED Decorative Transit/Single - Frozen	1.74	/mo	3720 LED Decorative Transit/Single - Frozen	2.01	/mo	0.27	933
934					3408 LED Roadway Architectural Bronze - Frozen	1.16	/mo	3408 LED Roadway Architectural Bronze - Frozen	1.34	/mo	0.18	934
935					4800 LED Roadway Architectural Bronze - Frozen	1.54	/mo	4800 LED Roadway Architectural Bronze - Frozen	1.78	/mo	0.24	935
936					4900 LED Roadway Architectural Bronze - Frozen	1.54	/mo	4900 LED Roadway Architectural Bronze - Frozen	1.78	/mo	0.24	936
937					7810 LED Roadway Architectural Bronze - Frozen	2.42	/mo	7810 LED Roadway Architectural Bronze - Frozen	2.80	/mo	0.38	937
938					8165 LED Roadway Architectural Bronze - Frozen	2.42	/mo	8165 LED Roadway Architectural Bronze - Frozen	2.80	/mo	0.38	938
939					11000 LED Roadway Architectural Bronze - Frozen	3.37	/mo	11000 LED Roadway Architectural Bronze - Frozen	3.89	/mo	0.52	939
940					11500 LED Roadway Architectural Bronze - Frozen	3.37	/mo	11500 LED Roadway Architectural Bronze - Frozen	3.89	/mo	0.52	940
941					3408 LED Cobra Roadway Gray - Frozen	1.15	/mo	3408 LED Cobra Roadway Gray - Frozen	1.33	/mo	0.18	941
942					4800 LED Cobra Roadway Gray - Frozen	1.53	/mo	4800 LED Cobra Roadway Gray - Frozen	1.77	/mo	0.24	942
943					4900 LED Cobra Roadway Gray - Frozen	1.53	/mo	4900 LED Cobra Roadway Gray - Frozen	1.77	/mo	0.24	943
944					7810 LED Cobra Roadway Gray - Frozen	2.41	/mo	7810 LED Cobra Roadway Gray - Frozen	2.78	/mo	0.37	944
945					8165 LED Cobra Roadway Gray - Frozen	2.41	/mo	8165 LED Cobra Roadway Gray - Frozen	2.78	/mo	0.37	945
946					11000 LED Cobra Roadway Gray - Frozen	3.36	/mo	11000 LED Cobra Roadway Gray - Frozen	3.88	/mo	0.52	946
947					11500 LED Cobra Roadway Gray - Frozen	3.36	/mo	11500 LED Cobra Roadway Gray - Frozen	3.88	/mo	0.52	947
948					14500 LED Flood - Frozen	3.40	/mo	14500 LED Flood - Frozen	3.93	/mo	0.53	948
949												949
950					**Pole (Company Owned)**			**Pole (Company Owned)**				950
951					12ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	$ 12.84	/mo	12ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	$ 14.83	/mo	$ 1.99	951
952					22ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	14.45	/mo	22ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	16.69	/mo	2.24	952
953					25ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	15.64	/mo	25ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	18.07	/mo	2.43	953
954					30ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	17.96	/mo	30ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	20.75	/mo	2.79	954
955					32ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	18.87	/mo	32ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	21.80	/mo	2.93	955
956					12ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	13.69	/mo	12ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	15.81	/mo	2.12	956
957					22ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	15.73	/mo	22ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	18.17	/mo	2.44	957
958					25ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	16.41	/mo	25ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	18.96	/mo	2.55	958
959					30ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	19.07	/mo	30ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	22.03	/mo	2.96	959
960					32ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	20.34	/mo	32ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	23.49	/mo	3.15	960
961					13ft Square Steel Flush Anchor Base - Frozen	14.72	/mo	13ft Square Steel Flush Anchor Base - Frozen	17.00	/mo	2.28	961

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	Line No.
962	E-47 (continued)	Dusk to Dawn Lighting Service	Rate	Sum & Win	15ft Square Steel Flush Anchor Base - Frozen	$ 13.15	/mo	15ft Square Steel Flush Anchor Base - Frozen	$ 15.19	/mo	$ 2.04	962
963					23ft Square Steel Flush Anchor Base - Frozen	15.60	/mo	23ft Square Steel Flush Anchor Base - Frozen	18.02	/mo	2.42	963
964					25ft Square Steel Flush Anchor Base - Frozen	17.15	/mo	25ft Square Steel Flush Anchor Base - Frozen	19.81	/mo	2.66	964
965					28ft Square Steel Flush Anchor Base - Frozen	19.04	/mo	28ft Square Steel Flush Anchor Base - Frozen	21.99	/mo	2.95	965
966					32ft Square Steel Flush Anchor Base - Frozen	18.93	/mo	32ft Square Steel Flush Anchor Base - Frozen	21.87	/mo	2.94	966
967					12ft Concrete Flush Anchor Base - Frozen	43.87	/mo	12ft Concrete Flush Anchor Base - Frozen	50.67	/mo	6.80	967
968					12ft Fiberglass Flush Anchor Base - Frozen	37.15	/mo	12ft Fiberglass Flush Anchor Base - Frozen	42.91	/mo	5.76	968
969					16ft Decorative Transit Anchor Base 4" - Frozen	36.22	/mo	16ft Decorative Transit Anchor Base 4" - Frozen	41.84	/mo	5.62	969
970					30ft Decorative Transit Anchor Base 6" - Frozen	69.93	/mo	30ft Decorative Transit Anchor Base 6" - Frozen	80.78	/mo	10.85	970
971					15ft Square Hinged Flush Anchor Base - Frozen	13.92	/mo	15ft Square Hinged Flush Anchor Base - Frozen	16.08	/mo	2.16	971
972					19ft Round Hinged Flush Anchor Base - Frozen	12.59	/mo	19ft Round Hinged Flush Anchor Base - Frozen	14.54	/mo	1.95	972
973					12ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	12.35	/mo	12ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	14.27	/mo	1.92	973
974					22ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	13.97	/mo	22ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	16.14	/mo	2.17	974
975					25ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	15.14	/mo	25ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	17.49	/mo	2.35	975
976					30ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	17.48	/mo	30ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	20.19	/mo	2.71	976
977					32ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	18.37	/mo	32ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	21.22	/mo	2.85	977
978					12ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	13.19	/mo	12ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	15.24	/mo	2.05	978
979					22ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	14.74	/mo	22ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	17.03	/mo	2.29	979
980					25ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	15.91	/mo	25ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	18.38	/mo	2.47	980
981					30ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	18.58	/mo	30ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	21.46	/mo	2.88	981
982					32ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	19.84	/mo	32ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	22.92	/mo	3.08	982
983					32ft Round Steel Pedestal Anchor Base - 3 Bolt - Frozen	22.80	/mo	32ft Round Steel Pedestal Anchor Base - 3 Bolt - Frozen	26.34	/mo	3.54	983
984					13ft Square Steel Pedestal Anchor Base - Frozen	14.24	/mo	13ft Square Steel Pedestal Anchor Base - Frozen	16.45	/mo	2.21	984
985					15ft Square Steel Pedestal Anchor Base - Frozen	14.56	/mo	15ft Square Steel Pedestal Anchor Base - Frozen	16.82	/mo	2.26	985
986					23ft Square Steel Pedestal Anchor Base - Frozen	15.11	/mo	23ft Square Steel Pedestal Anchor Base - Frozen	17.45	/mo	2.34	986
987					25ft Square Steel Pedestal Anchor Base - Frozen	16.67	/mo	25ft Square Steel Pedestal Anchor Base - Frozen	19.26	/mo	2.59	987
988					28ft Square Steel Pedestal Anchor Base - Frozen	18.52	/mo	28ft Square Steel Pedestal Anchor Base - Frozen	21.39	/mo	2.87	988
989					32ft Square Steel Pedestal Anchor Base - Frozen	19.23	/mo	32ft Square Steel Pedestal Anchor Base - Frozen	22.21	/mo	2.98	989

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
990	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	19ft Round Steel Direct Bury - Frozen	$ 19.43	/mo	19ft Round Steel Direct Bury - Frozen	$ 22.44	/mo	$ 3.01	990
991	(continued)	Service			30ft Round Steel Direct Bury - Frozen	15.17	/mo	30ft Round Steel Direct Bury - Frozen	17.52	/mo	2.35	991
992					38ft Round Steel Direct Bury - Frozen	18.51	/mo	38ft Round Steel Direct Bury - Frozen	21.38	/mo	2.87	992
993					40ft Round Steel Direct Bury Self Support - Frozen	22.80	/mo	40ft Round Steel Direct Bury Self Support - Frozen	26.34	/mo	3.54	993
994					25ft Round Steel Direct Bury Stepped - Frozen	52.45	/mo	25ft Round Steel Direct Bury Stepped - Frozen	60.59	/mo	8.14	994
995					32ft Round Steel Direct Bury Stepped - Frozen	55.24	/mo	32ft Round Steel Direct Bury Stepped - Frozen	63.81	/mo	8.57	995
996					49ft Round Steel Direct Bury Stepped - Frozen	68.57	/mo	49ft Round Steel Direct Bury Stepped - Frozen	79.21	/mo	10.64	996
997					34ft Square Steel Direct Bury 4" - Frozen	16.74	/mo	34ft Square Steel Direct Bury 4" - Frozen	19.34	/mo	2.60	997
998					20ft Square Steel Direct Bury 5" - Frozen	15.90	/mo	20ft Square Steel Direct Bury 5" - Frozen	18.37	/mo	2.47	998
999					30ft Square Steel Direct Bury 5" - Frozen	16.57	/mo	30ft Square Steel Direct Bury 5" - Frozen	19.14	/mo	2.57	999
1000					38ft Square Steel Direct Bury 5" - Frozen	17.98	/mo	38ft Square Steel Direct Bury 5" - Frozen	20.77	/mo	2.79	1000
1001					28ft Square Steel Direct Bury 8" - Frozen	30.01	/mo	28ft Square Steel Direct Bury 8" - Frozen	34.66	/mo	4.65	1001
1002					32ft Square Steel Direct Bury 8" - Frozen	31.37	/mo	32ft Square Steel Direct Bury 8" - Frozen	36.24	/mo	4.87	1002
1003					41ft6in Decorative Transit Direct Bury - Frozen	21.60	/mo	41ft6in Decorative Transit Direct Bury - Frozen	24.95	/mo	3.35	1003
1004					47ft Decorative Transit Direct Bury - Frozen	26.91	/mo	47ft Decorative Transit Direct Bury - Frozen	31.08	/mo	4.17	1004
1005					35ft Steel Distribution Pole - Frozen	24.84	/mo	35ft Steel Distribution Pole - Frozen	28.69	/mo	3.85	1005
1006					16ft Decorative Transit Anchor Post Top - Frozen	37.00	/mo	16ft Decorative Transit Anchor Post Top - Frozen	42.74	/mo	5.74	1006
1007					23ft Gray Steel/Fiberglass Post Top - Frozen	12.83	/mo	23ft Gray Steel/Fiberglass Post Top - Frozen	14.82	/mo	1.99	1007
1008					23ft Black Steel Post Top - Frozen	14.14	/mo	23ft Black Steel Post Top - Frozen	16.33	/mo	2.19	1008
1009					30 Ft Wood Pole - Frozen	9.44	/mo	30 Ft Wood Pole - Frozen	10.90	/mo	1.46	1009
1010					35 Ft Wood Pole - Frozen	9.44	/mo	35 Ft Wood Pole - Frozen	10.90	/mo	1.46	1010
1011					40 Ft Wood Pole - Frozen	13.44	/mo	40 Ft Wood Pole - Frozen	15.52	/mo	2.08	1011
1012												1012
1013					4ft Flush Anchor Base - Frozen	$ 10.45	/mo	4ft Flush Anchor Base - Frozen	$ 12.07	/mo	$ 1.62	1013
1014					6ft Flush Anchor Base - Frozen	12.47	/mo	6ft Flush Anchor Base - Frozen	14.40	/mo	1.93	1014
1015					8ft Pedestal Anchor Base - Frozen	14.29	/mo	8ft Pedestal Anchor Base - Frozen	16.51	/mo	2.22	1015
1016					4ft 6" Pedestal Anchor Base" - Frozen	9.91	/mo	4ft 6" Pedestal Anchor Base" - Frozen	11.45	/mo	1.54	1016
1017												1017
1018					1. 100' OH, UG if conduit by customer - Frozen	$ 3.69	/mo	1. 100' OH, UG if conduit by customer - Frozen	$ 4.26	/mo	$ 0.57	1018
1019					2. HPS not accessible by bucket - Frozen	2.95	/mo	2. HPS not accessible by bucket - Frozen	3.41	/mo	0.46	1019
1020					3. MH not accessible by bucket - Frozen	6.38	/mo	3. MH not accessible by bucket - Frozen	7.37	/mo	0.99	1020
1021												1021
1022					Generation Charge - Frozen	$ 0.06621	/kWh	Generation Charge - Frozen	$ 0.07676	/kWh	$ 0.01055	1022
1023					T&D, RCS,SB Charge - Frozen	0.02682	/kWh	T&D, RCS,SB Charge - Frozen	0.03126	/kWh	0.00	1023
1024					NON-STANDARD CHARGES			NON-STANDARD CHARGES				1024
1025					Service Charge - Frozen	$ 3.54	/mo	Service Charge - Frozen	$ 4.09	/mo	$ 0.55	1025
1026					All kWh - Frozen	0.06857	/kWh	All kWh - Frozen	0.07949	/kWh	0.01	1026

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) Change (I) - (F)	Line No.
1027										1027
1028										1028
1029	E-56	Electric Service for	Basic							1029
1030		Partial Requirements	Service	Sum & Win						1030
1031		Service for CG			Basic Service Charge	per applicable rate	Basic Service Charge	per applicable rate		1031
1032		installations of 100kw				schedule		schedule		1032
1033			Supplemental	Sum & Win						1033
1034			Service		All Supplemental Charges	per applicable rate	All Supplemental Charges	per applicable rate		1034
1035						schedule		schedule		1035
1036			Back-Up	Sum & Win						1036
1037			Service		Back-Up Service with E-34 On-Peak	$ 0.631 /kW-day	Back-Up Service with E-34 On-Peak	$ 0.775 /kW-day	$ 0.144	1037
1038					Back-Up Service with E-34 Off-Peak	N/A	Back-Up Service with E-34 Off-Peak	N/A		1038
1039					Back-Up Service with E-32 On-Peak	$ 0.128 /kW-day	Back-Up Service with E-32 On-Peak	$ 0.157 /kW-day	$ 0.029	1039
1040					Back-Up Service with E-32 Off-Peak	N/A	Back-Up Service with E-32 Off-Peak	N/A		1040
1041			Maint.	Sum & Win						1041
1042			Service		Scheduled Maintenance On-Peak	1/2 Back-up Charge	Scheduled Maintenance On-Peak	1/2 Back-up Charge		1042
1043					Scheduled Maintenance Off-Peak	N/A	Scheduled Maintenance Off-Peak	N/A		1043
1044			Excess	Sum & Win						1044
1045					Secondary Service Excess Charge	$ 53.452 /kW	Secondary Service Excess Charge	$ 65.676 /kW	$ 12.224	1045
1046					Primary Service Excess Charge	50.738 /kW	Primary Service Excess Charge	62.342 /kW	11.604	1046
1047					Transmission Service Excess Charge	37.246 /kW	Transmission Service Excess Charge	45.764 /kW	8.518	1047
1048										1048
1049	E-68	Street Lighting Service	Rate	Sum & Win	**EQUIPMENT TIERS (Investment by Company)**		**EQUIPMENT TIERS (Investment by Company)**			1049
1050					Equipment Tier A	$ 5.72 /mo	Equipment Tier A	$ 6.77 /mo	$ 1.05	1050
1051					Equipment Tier B	6.97 /mo	Equipment Tier B	8.25 /mo	1.28	1051
1052					Equipment Tier C	8.36 /mo	Equipment Tier C	9.90 /mo	1.54	1052
1053					Equipment Tier D	9.99 /mo	Equipment Tier D	11.83 /mo	1.84	1053
1054					Equipment Tier E	12.64 /mo	Equipment Tier E	14.98 /mo	2.34	1054
1055					Equipment Tier F	14.07 /mo	Equipment Tier F	16.67 /mo	2.60	1055
1056					Equipment Tier G	15.38 /mo	Equipment Tier G	18.23 /mo	2.85	1056
1057					Equipment Tier H	17.44 /mo	Equipment Tier H	20.67 /mo	3.23	1057
1058					Equipment Tier I	19.40 /mo	Equipment Tier I	23.00 /mo	3.60	1058
1059					Equipment Tier J	23.65 /mo	Equipment Tier J	28.04 /mo	4.39	1059
1060					Equipment Tier K	26.29 /mo	Equipment Tier K	31.17 /mo	4.88	1060
1061										1061
1062					**EQUIPMENT TIERS (Investment by Customer)**		**EQUIPMENT TIERS (Investment by Customer)**			1062
1063					Equipment Tier A	$ 1.75 /mo	Equipment Tier A	$ 2.06 /mo	$ 0.31	1063
1064					Equipment Tier B	2.12 /mo	Equipment Tier B	2.50 /mo	0.38	1064
1065					Equipment Tier C	2.60 /mo	Equipment Tier C	3.06 /mo	0.46	1065
1066					Equipment Tier D	3.32 /mo	Equipment Tier D	3.92 /mo	0.60	1066
1067					Equipment Tier E	3.68 /mo	Equipment Tier E	4.35 /mo	0.67	1067
1068					Equipment Tier F	4.08 /mo	Equipment Tier F	4.82 /mo	0.74	1068
1069					Equipment Tier G	4.49 /mo	Equipment Tier G	5.31 /mo	0.82	1069
1070					Equipment Tier H	5.04 /mo	Equipment Tier H	5.96 /mo	0.92	1070
1071					Equipment Tier I	6.12 /mo	Equipment Tier I	7.24 /mo	1.12	1071
1072					Equipment Tier J	6.73 /mo	Equipment Tier J	7.96 /mo	1.23	1072
1073					Equipment Tier K	7.45 /mo	Equipment Tier K	8.82 /mo	1.37	1073
1074										1074
1075					Generation Charge	$ 0.06621 /kWh	Generation Charge	$ 0.07856 /kWh	$ 0.01235	1075
1076					T&D, RCS,SB Charge	0.02682 /kWh	T&D, RCS,SB Charge	0.03182 /kWh	0.00500	1076
1077										1077

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	Line No.
1078	E-68	Street Lighting Service	Rate	Sum & Win	**Poles (Investment by Company)**			**Poles (Investment by Company)**				1078
1079	(continued)				12ft Round Steel Flush Anchor Base - 1 Simplex	$ 12.84	/mo	12ft Round Steel Flush Anchor Base - 1 Simplex	$ 15.21	/mo	$ 2.37	1079
1080					22ft Round Steel Flush Anchor Base - 1 Simplex	14.45	/mo	22ft Round Steel Flush Anchor Base - 1 Simplex	17.12	/mo	2.67	1080
1081					25ft Round Steel Flush Anchor Base - 1 Simplex	15.64	/mo	25ft Round Steel Flush Anchor Base - 1 Simplex	18.54	/mo	2.90	1081
1082					30ft Round Steel Flush Anchor Base - 1 Simplex	17.96	/mo	30ft Round Steel Flush Anchor Base - 1 Simplex	21.29	/mo	3.33	1082
1083					32ft Round Steel Flush Anchor Base - 1 Simplex	18.87	/mo	32ft Round Steel Flush Anchor Base - 1 Simplex	22.37	/mo	3.50	1083
1084					12ft Round Steel Flush Anchor Base - 2 Simplex	13.69	/mo	12ft Round Steel Flush Anchor Base - 2 Simplex	16.22	/mo	2.53	1084
1085					22ft Round Steel Flush Anchor Base - 2 Simplex	15.73	/mo	22ft Round Steel Flush Anchor Base - 2 Simplex	18.64	/mo	2.91	1085
1086					25ft Round Steel Flush Anchor Base - 2 Simplex	16.41	/mo	25ft Round Steel Flush Anchor Base - 2 Simplex	19.45	/mo	3.04	1086
1087					30ft Round Steel Flush Anchor Base - 2 Simplex	19.07	/mo	30ft Round Steel Flush Anchor Base - 2 Simplex	22.61	/mo	3.54	1087
1088					32ft Round Steel Flush Anchor Base - 2 Simplex	20.34	/mo	32ft Round Steel Flush Anchor Base - 2 Simplex	24.11	/mo	3.77	1088
1089					13ft Square Steel Flush Anchor Base	14.72	/mo	13ft Square Steel Flush Anchor Base	17.44	/mo	2.72	1089
1090					15ft Square Steel Flush Anchor Base	13.15	/mo	15ft Square Steel Flush Anchor Base	15.58	/mo	2.43	1090
1091					23ft Square Steel Flush Anchor Base	15.60	/mo	23ft Square Steel Flush Anchor Base	18.49	/mo	2.89	1091
1092					25ft Square Steel Flush Anchor Base	17.15	/mo	25ft Square Steel Flush Anchor Base	20.33	/mo	3.18	1092
1093					28ft Square Steel Flush Anchor Base	19.04	/mo	28ft Square Steel Flush Anchor Base	22.57	/mo	3.53	1093
1094					32ft Square Steel Flush Anchor Base	18.93	/mo	32ft Square Steel Flush Anchor Base	22.44	/mo	3.51	1094
1095					12ft Concrete Flush Anchor Base	43.87	/mo	12ft Concrete Flush Anchor Base	52.03	/mo	8.16	1095
1096					12ft Fiberglass Flush Anchor Base	37.15	/mo	12ft Fiberglass Flush Anchor Base	44.06	/mo	6.91	1096
1097					16ft Decorative Transit Pedestrian Anchor Base	36.22	/mo	16ft Decorative Transit Pedestrian Anchor Base	42.95	/mo	6.73	1097
1098					30ft Transit Anchor Base 6"	69.93	/mo	30ft Transit Anchor Base 6"	82.95	/mo	13.02	1098
1099					15ft Square Hinged Flush Anchor Base	13.92	/mo	15ft Square Hinged Flush Anchor Base	16.50	/mo	2.58	1099
1100					19ft Round Hinged Flush Anchor Base	12.59	/mo	19ft Round Hinged Flush Anchor Base	14.92	/mo	2.33	1100
1101					12ft Round Steel Pedestal Anchor Base - 1 Simplex	12.35	/mo	12ft Round Steel Pedestal Anchor Base - 1 Simplex	14.63	/mo	2.28	1101
1102					22ft Round Steel Pedestal Anchor Base - 1 Simplex	13.97	/mo	22ft Round Steel Pedestal Anchor Base - 1 Simplex	16.55	/mo	2.58	1102
1103					25ft Round Steel Pedestal Anchor Base - 1 Simplex	15.14	/mo	25ft Round Steel Pedestal Anchor Base - 1 Simplex	17.94	/mo	2.80	1103
1104					30ft Round Steel Pedestal Anchor Base - 1 Simplex	17.48	/mo	30ft Round Steel Pedestal Anchor Base - 1 Simplex	20.72	/mo	3.24	1104
1105					32ft Round Steel Pedestal Anchor Base - 1 Simplex	18.37	/mo	32ft Round Steel Pedestal Anchor Base - 1 Simplex	21.78	/mo	3.41	1105
1106					12ft Round Steel Pedestal Anchor Base - 2 Simplex	13.19	/mo	12ft Round Steel Pedestal Anchor Base - 2 Simplex	15.63	/mo	2.44	1106
1107					22ft Round Steel Pedestal Anchor Base - 2 Simplex	14.74	/mo	22ft Round Steel Pedestal Anchor Base - 2 Simplex	17.47	/mo	2.73	1107
1108					25ft Round Steel Pedestal Anchor Base - 2 Simplex	15.91	/mo	25ft Round Steel Pedestal Anchor Base - 2 Simplex	18.86	/mo	2.95	1108
1109					30ft Round Steel Pedestal Anchor Base - 2 Simplex	18.58	/mo	30ft Round Steel Pedestal Anchor Base - 2 Simplex	22.02	/mo	3.44	1109
1110					32ft Round Steel Pedestal Anchor Base - 2 Simplex	19.84	/mo	32ft Round Steel Pedestal Anchor Base - 2 Simplex	23.52	/mo	3.68	1110

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1111	E-68 (continued)	Street Lighting Service	Rate	Sum & Win	32ft Round Steel Pedestal Anchor Base - 3 Bolt	$ 22.80	/mo	32ft Round Steel Pedestal Anchor Base - 3 Bolt	$ 27.03	/mo	$ 4.23	1111
1112					13ft Square Steel Pedestal Anchor Base	14.24	/mo	13ft Square Steel Pedestal Anchor Base	16.88	/mo	2.64	1112
1113					15ft Square Steel Pedestal Anchor Base	14.56	/mo	15ft Square Steel Pedestal Anchor Base	17.25	/mo	2.69	1113
1114					23ft Square Steel Pedestal Anchor Base	15.11	/mo	23ft Square Steel Pedestal Anchor Base	17.91	/mo	2.80	1114
1115					25ft Square Steel Pedestal Anchor Base	16.67	/mo	25ft Square Steel Pedestal Anchor Base	19.76	/mo	3.09	1115
1116					28ft Square Steel Pedestal Anchor Base	18.52	/mo	28ft Square Steel Pedestal Anchor Base	21.95	/mo	3.43	1116
1117					32ft Square Steel Pedestal Anchor Base	19.23	/mo	32ft Square Steel Pedestal Anchor Base	22.80	/mo	3.57	1117
1118					19ft Round Steel Direct Bury	19.43	/mo	19ft Round Steel Direct Bury	23.03	/mo	3.60	1118
1119					30ft Round Steel Direct Bury	15.17	/mo	30ft Round Steel Direct Bury	17.98	/mo	2.81	1119
1120					38ft Round Steel Direct Bury	18.51	/mo	38ft Round Steel Direct Bury	21.94	/mo	3.43	1120
1121						22.80	/mo		27.03	/mo	4.23	1121
					40ft Round Steel Direct Bury Self Support			40ft Round Steel Direct Bury Self Support				
1122					25ft Round Steel Direct Bury Stepped	52.45	/mo	25ft Round Steel Direct Bury Stepped	62.21	/mo	9.76	1122
1123					32ft Round Steel Direct Bury Stepped	55.24	/mo	32ft Round Steel Direct Bury Stepped	65.52	/mo	10.28	1123
1124					49ft Round Steel Direct Bury Stepped	68.57	/mo	49ft Round Steel Direct Bury Stepped	81.34	/mo	12.77	1124
1125					34ft Square Steel Direct Bury 4"	16.74	/mo	34ft Square Steel Direct Bury 4"	19.84	/mo	3.10	1125
1126					20ft Square Steel Direct Bury 5"	15.90	/mo	20ft Square Steel Direct Bury 5"	18.84	/mo	2.94	1126
1127					30ft Square Steel Direct Bury 5"	16.57	/mo	30ft Square Steel Direct Bury 5"	19.64	/mo	3.07	1127
1128					38ft Square Steel Direct Bury 5"	17.98	/mo	38ft Square Steel Direct Bury 5"	21.31	/mo	3.33	1128
1129					28ft Square Steel Direct Bury 8"	30.01	/mo	28ft Square Steel Direct Bury 8"	35.59	/mo	5.58	1129
1130					32ft Square Steel Direct Bury 8"	31.37	/mo	32ft Square Steel Direct Bury 8"	37.20	/mo	5.83	1130
1131					41ft6in Decorative Transit Direct Bury	21.60	/mo	41ft6in Decorative Transit Direct Bury	25.61	/mo	4.01	1131
1132					47ft Decorative Transit Direct Bury	26.91	/mo	47ft Decorative Transit Direct Bury	31.91	/mo	5.00	1132
1133					35ft Steel Distribution Pole	24.84	/mo	35ft Steel Distribution Pole	29.45	/mo	4.61	1133
1134						37.00	/mo		43.88	/mo	6.88	1134
					16ft Decorative Transit Anchor Post Top			16ft Decorative Transit Anchor Post Top				
1135					23ft Gray Steel/Fiberglass Post Top	12.83	/mo	23ft Gray Steel/Fiberglass Post Top	15.20	/mo	2.37	1135
1136					23ft Black Steel Post Top	14.14	/mo	23ft Black Steel Post Top	16.76	/mo	2.62	1136
1137					Existing distribution pole suitable for streetlight use	1.56	/mo	Existing distribution pole suitable for streetlight use	1.83	/mo	0.27	1137
1138								30ft Wood Pole	11.20	/mo	11.20	1138
1139								35ft Wood Pole	11.20	/mo	11.20	1139
1140								40ft Wood Pole	16.00	/mo	16.00	1140
1141												1141
1142					4ft Flush Anchor Base	$ 10.45	/mo	4ft Flush Anchor Base	$ 12.38	/mo	$ 1.93	1142
1143					6ft Flush Anchor Base	12.47	/mo	6ft Flush Anchor Base	14.78	/mo	2.31	1143
1144					8ft Pedestal Anchor Base	14.29	/mo	8ft Pedestal Anchor Base	16.93	/mo	2.64	1144
1145					4ft 6" Pedestal Anchor Base	9.91	/mo	4ft 6" Pedestal Anchor Base	11.74	/mo	1.83	1145
1146												1146

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) Change (I) - (F)	Line No.
1147	E-68	Street Lighting Service	Rate	Sum & Win	**Poles (Investment by Others)**		**Poles (Investment by Others)**			1147
1148	(continued)				12ft Round Steel Flush Anchor Base - 1 Simplex	$ 1.77 /mo	12ft Round Steel Flush Anchor Base - 1 Simplex	$ 2.08 /mo	$ 0.31	1148
1149					22ft Round Steel Flush Anchor Base - 1 Simplex	1.99 /mo	22ft Round Steel Flush Anchor Base - 1 Simplex	2.34 /mo	0.35	1149
1150					25ft Round Steel Flush Anchor Base - 1 Simplex	2.16 /mo	25ft Round Steel Flush Anchor Base - 1 Simplex	2.54 /mo	0.38	1150
1151					30ft Round Steel Flush Anchor Base - 1 Simplex	2.47 /mo	30ft Round Steel Flush Anchor Base - 1 Simplex	2.91 /mo	0.44	1151
1152					32ft Round Steel Flush Anchor Base - 1 Simplex	2.50 /mo	32ft Round Steel Flush Anchor Base - 1 Simplex	2.95 /mo	0.45	1152
1153					12ft Round Steel Flush Anchor Base - 2 Simplex	1.89 /mo	12ft Round Steel Flush Anchor Base - 2 Simplex	2.22 /mo	0.33	1153
1154					22ft Round Steel Flush Anchor Base - 2 Simplex	2.17 /mo	22ft Round Steel Flush Anchor Base - 2 Simplex	2.55 /mo	0.38	1154
1155					25ft Round Steel Flush Anchor Base - 2 Simplex	2.26 /mo	25ft Round Steel Flush Anchor Base - 2 Simplex	2.66 /mo	0.40	1155
1156					30ft Round Steel Flush Anchor Base - 2 Simplex	2.63 /mo	30ft Round Steel Flush Anchor Base - 2 Simplex	3.10 /mo	0.47	1156
1157					32ft Round Steel Flush Anchor Base - 2 Simplex	2.81 /mo	32ft Round Steel Flush Anchor Base - 2 Simplex	3.31 /mo	0.50	1157
1158					13ft Square Steel Flush Anchor Base	2.02 /mo	13ft Square Steel Flush Anchor Base	2.38 /mo	0.36	1158
1159					15ft Square Steel Flush Anchor Base	1.81 /mo	15ft Square Steel Flush Anchor Base	2.13 /mo	0.32	1159
1160					23ft Square Steel Flush Anchor Base	2.15 /mo	23ft Square Steel Flush Anchor Base	2.53 /mo	0.38	1160
1161					25ft Square Steel Flush Anchor Base	2.36 /mo	25ft Square Steel Flush Anchor Base	2.78 /mo	0.42	1161
1162					28ft Square Steel Flush Anchor Base	2.62 /mo	28ft Square Steel Flush Anchor Base	3.09 /mo	0.47	1162
1163					32ft Square Steel Flush Anchor Base	2.61 /mo	32ft Square Steel Flush Anchor Base	3.08 /mo	0.47	1163
1164					12ft Concrete Flush Anchor Base	6.04 /mo	12ft Concrete Flush Anchor Base	7.15 /mo	1.11	1164
1165					12ft Fiberglass Flush Anchor Base	5.11 /mo	12ft Fiberglass Flush Anchor Base	6.04 /mo	0.93	1165
1166					16ft Decorative Transit Pedestrian Anchor Base	5.00 /mo	16ft Decorative Transit Pedestrian Anchor Base	5.91 /mo	0.91	1166
1167					30ft Transit Anchor Base 6"	9.63 /mo	30ft Transit Anchor Base 6"	11.41 /mo	1.78	1167
1168					15ft Square Hinged Flush Anchor Base	1.14 /mo	15ft Square Hinged Flush Anchor Base	1.33 /mo	0.19	1168
1169					19ft Round Hinged Flush Anchor Base	1.03 /mo	19ft Round Hinged Flush Anchor Base	1.20 /mo	0.17	1169
1170					12ft Round Steel Pedestal Anchor Base - 1 Simplex	1.69 /mo	12ft Round Steel Pedestal Anchor Base - 1 Simplex	1.99 /mo	0.30	1170
1171					22ft Round Steel Pedestal Anchor Base - 1 Simplex	1.92 /mo	22ft Round Steel Pedestal Anchor Base - 1 Simplex	2.26 /mo	0.34	1171
1172					25ft Round Steel Pedestal Anchor Base - 1 Simplex	2.09 /mo	25ft Round Steel Pedestal Anchor Base - 1 Simplex	2.46 /mo	0.37	1172
1173					30ft Round Steel Pedestal Anchor Base - 1 Simplex	2.42 /mo	30ft Round Steel Pedestal Anchor Base - 1 Simplex	2.85 /mo	0.43	1173
1174					32ft Round Steel Pedestal Anchor Base - 1 Simplex	2.53 /mo	32ft Round Steel Pedestal Anchor Base - 1 Simplex	2.98 /mo	0.45	1174
1175					12ft Round Steel Pedestal Anchor Base - 2 Simplex	1.81 /mo	12ft Round Steel Pedestal Anchor Base - 2 Simplex	2.13 /mo	0.32	1175
1176					22ft Round Steel Pedestal Anchor Base - 2 Simplex	2.02 /mo	22ft Round Steel Pedestal Anchor Base - 2 Simplex	2.38 /mo	0.36	1176
1177					25ft Round Steel Pedestal Anchor Base - 2 Simplex	2.18 /mo	25ft Round Steel Pedestal Anchor Base - 2 Simplex	2.57 /mo	0.39	1177
1178					30ft Round Steel Pedestal Anchor Base - 2 Simplex	2.55 /mo	30ft Round Steel Pedestal Anchor Base - 2 Simplex	3.01 /mo	0.46	1178
1179					32ft Round Steel Pedestal Anchor Base - 2 Simplex	2.73 /mo	32ft Round Steel Pedestal Anchor Base - 2 Simplex	3.22 /mo	0.49	1179

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1180	E-68 (continued)	Street Lighting Service	Rate	Sum & Win	32ft Round Steel Pedestal Anchor Base - 3 Bolt	$ 3.13	/mo	32ft Round Steel Pedestal Anchor Base - 3 Bolt	$ 3.69	/mo	$ 0.56	1180
1181					13ft Square Steel Pedestal Anchor Base	1.97	/mo	13ft Square Steel Pedestal Anchor Base	2.32	/mo	0.35	1181
1182					15ft Square Steel Pedestal Anchor Base	1.99	/mo	15ft Square Steel Pedestal Anchor Base	2.34	/mo	0.35	1182
1183					23ft Square Steel Pedestal Anchor Base	2.09	/mo	23ft Square Steel Pedestal Anchor Base	2.46	/mo	0.37	1183
1184					25ft Square Steel Pedestal Anchor Base	2.31	/mo	25ft Square Steel Pedestal Anchor Base	2.72	/mo	0.41	1184
1185					28ft Square Steel Pedestal Anchor Base	2.55	/mo	28ft Square Steel Pedestal Anchor Base	3.01	/mo	0.46	1185
1186					32ft Square Steel Pedestal Anchor Base	2.63	/mo	32ft Square Steel Pedestal Anchor Base	3.10	/mo	0.47	1186
1187					19ft Round Steel Direct Bury	2.68	/mo	19ft Round Steel Direct Bury	3.16	/mo	0.48	1187
1188					30ft Round Steel Direct Bury	2.81	/mo	30ft Round Steel Direct Bury	3.31	/mo	0.50	1188
1189					38ft Round Steel Direct Bury	2.88	/mo	38ft Round Steel Direct Bury	3.40	/mo	0.52	1189
1190						3.61	/mo		4.26	/mo	0.65	1190
					40ft Round Steel Direct Bury Self Support			40ft Round Steel Direct Bury Self Support				
1191					25ft Round Steel Direct Bury Stepped	4.28	/mo	25ft Round Steel Direct Bury Stepped	5.06	/mo	0.78	1191
1192					32ft Round Steel Direct Bury Stepped	4.51	/mo	32ft Round Steel Direct Bury Stepped	5.33	/mo	0.82	1192
1193					49ft Round Steel Direct Bury Stepped	9.45	/mo	49ft Round Steel Direct Bury Stepped	11.19	/mo	1.74	1193
1194					34ft Square Steel Direct Bury 4"	2.90	/mo	34ft Square Steel Direct Bury 4"	3.42	/mo	0.52	1194
1195					20ft Square Steel Direct Bury 5"	2.63	/mo	20ft Square Steel Direct Bury 5"	3.10	/mo	0.47	1195
1196					30ft Square Steel Direct Bury 5"	2.73	/mo	30ft Square Steel Direct Bury 5"	3.22	/mo	0.49	1196
1197					38ft Square Steel Direct Bury 5"	3.12	/mo	38ft Square Steel Direct Bury 5"	3.68	/mo	0.56	1197
1198					28ft Square Steel Direct Bury 8"	2.44	/mo	28ft Square Steel Direct Bury 8"	2.87	/mo	0.43	1198
1199					32ft Square Steel Direct Bury 8"	2.57	/mo	32ft Square Steel Direct Bury 8"	3.03	/mo	0.46	1199
1200					41ft6in Decorative Transit Direct Bury	3.17	/mo	41ft6in Decorative Transit Direct Bury	3.74	/mo	0.57	1200
1201					47ft Decorative Transit Direct Bury	3.96	/mo	47ft Decorative Transit Direct Bury	4.68	/mo	0.72	1201
1202					35ft Steel Distribution Pole	3.27	/mo	35ft Steel Distribution Pole	3.86	/mo	0.59	1202
1203					16ft Decorative Transit Anchor Post Top	5.08	/mo	16ft Decorative Transit Anchor Post Top	6.01	/mo	0.93	1203
1204					23ft Gray Steel/Fiberglass Post Top	2.11	/mo	23ft Gray Steel/Fiberglass Post Top	2.48	/mo	0.37	1204
1205					23ft Black Steel Post Top	2.33	/mo	23ft Black Steel Post Top	2.74	/mo	0.41	1205
1206												1206
1207					4ft Flush Anchor Base	$ 1.44	/mo	4ft Flush Anchor Base	$ 1.69	/mo	$ 0.25	1207
1208					6ft Flush Anchor Base	2.16	/mo	6ft Flush Anchor Base	2.54	/mo	0.38	1208
1209					8ft Pedestal Anchor Base	2.49	/mo	8ft Pedestal Anchor Base	2.93	/mo	0.44	1209
1210					4ft 6" Pedestal Anchor Base	1.71	/mo	4ft 6" Pedestal Anchor Base	2.01	/mo	0.30	1210
1211												1211
1212						$ 0.16652	per foot		$ 0.19757	per foot	$ 0.03105	1212
					Underground Circuit Charges under paving			Underground Circuit Charges under paving				
1213					Underground Circuit Charges not under paving	0.05877	per foot	Underground Circuit Charges not under paving	0.06973	per foot	0.01096	1213
1214												1214

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	Line No.
1215	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES (Investment By Company)**			**FIXTURES (Investment By Company)**				1215
1216					3835 LED Acorn - Frozen	$ 21.19	/mo	3835 LED Acorn - Frozen	$ 25.12	/mo	$ 3.93	1216
1217					4796 LED Acorn - Frozen	17.02	/mo	4796 LED Acorn - Frozen	20.17	/mo	3.15	1217
1218					5003 LED Acorn - Frozen	22.97	/mo	5003 LED Acorn - Frozen	27.23	/mo	4.26	1218
1219					5904 LED Acorn - Frozen	22.56	/mo	5904 LED Acorn - Frozen	26.75	/mo	4.19	1219
1220					6000 IND Acorn - Frozen	18.85	/mo	6000 IND Acorn - Frozen	22.34	/mo	3.49	1220
1221					6200 IND Architectural - Frozen	9.92	/mo	6200 IND Architectural - Frozen	11.75	/mo	1.83	1221
1222					8400 IND Architectural - Frozen	10.47	/mo	8400 IND Architectural - Frozen	12.40	/mo	1.93	1222
1223					10200 IND Architectural - Frozen	11.51	/mo	10200 IND Architectural - Frozen	13.64	/mo	2.13	1223
1224					13000 IND Architectural - Frozen	12.71	/mo	13000 IND Architectural - Frozen	15.06	/mo	2.35	1224
1225					20500 IND Architectural - Frozen	14.48	/mo	20500 IND Architectural - Frozen	17.16	/mo	2.68	1225
1226					22500 IND Architectural - Frozen	17.27	/mo	22500 IND Architectural - Frozen	20.47	/mo	3.20	1226
1227					3300 LED Architectural - Frozen	10.03	/mo	3300 LED Architectural - Frozen	11.88	/mo	1.85	1227
1228					3800 LED Architectural - Frozen	7.57	/mo	3800 LED Architectural - Frozen	8.96	/mo	1.39	1228
1229					3900 LED Architectural - Frozen	9.76	/mo	3900 LED Architectural - Frozen	11.56	/mo	1.80	1229
1230					4050 LED Architectural - Frozen	18.25	/mo	4050 LED Architectural - Frozen	21.63	/mo	3.38	1230
1231					4100 LED Architectural - Frozen	10.13	/mo	4100 LED Architectural - Frozen	12.00	/mo	1.87	1231
1232					4800 LED Architectural - Frozen	8.10	/mo	4800 LED Architectural - Frozen	9.59	/mo	1.49	1232
1233					5000 LED Architectural - Frozen	9.41	/mo	5000 LED Architectural - Frozen	11.14	/mo	1.73	1233
1234					5100 LED Architectural - Frozen	9.97	/mo	5100 LED Architectural - Frozen	11.81	/mo	1.84	1234
1235					5300 LED Architectural - Frozen	10.26	/mo	5300 LED Architectural - Frozen	12.15	/mo	1.89	1235
1236					5800 LED Architectural - Frozen	17.44	/mo	5800 LED Architectural - Frozen	20.67	/mo	3.23	1236
1237					5890 LED Architectural - Frozen	20.14	/mo	5890 LED Architectural - Frozen	23.88	/mo	3.74	1237
1238					6000 LED Architectural - Frozen	18.25	/mo	6000 LED Architectural - Frozen	21.63	/mo	3.38	1238
1239					6000 LED Architectural - Frozen	19.48	/mo	6000 LED Architectural - Frozen	23.09	/mo	3.61	1239
1240					6400 LED Architectural - Frozen	17.52	/mo	6400 LED Architectural - Frozen	20.77	/mo	3.25	1240
1241					6810 LED Architectural - Frozen	18.50	/mo	6810 LED Architectural - Frozen	21.93	/mo	3.43	1241
1242					7100 LED Architectural - Frozen	19.30	/mo	7100 LED Architectural - Frozen	22.88	/mo	3.58	1242
1243					7400 LED Architectural - Frozen	20.00	/mo	7400 LED Architectural - Frozen	23.71	/mo	3.71	1243
1244					7500 LED Architectural - Frozen	19.67	/mo	7500 LED Architectural - Frozen	23.32	/mo	3.65	1244
1245					7700 LED Architectural - Frozen	18.03	/mo	7700 LED Architectural - Frozen	21.37	/mo	3.34	1245
1246					8200 LED Architectural - Frozen	10.24	/mo	8200 LED Architectural - Frozen	12.13	/mo	1.89	1246
1247					8200 LED Architectural - Frozen	11.63	/mo	8200 LED Architectural - Frozen	13.78	/mo	2.15	1247
1248					8300 LED Architectural - Frozen	17.56	/mo	8300 LED Architectural - Frozen	20.81	/mo	3.25	1248
1249					8300 LED Architectural - Frozen	12.19	/mo	8300 LED Architectural - Frozen	14.44	/mo	2.25	1249
1250					8500 LED Architectural - Frozen	11.45	/mo	8500 LED Architectural - Frozen	13.56	/mo	2.11	1250
1251					9020 LED Architectural - Frozen	22.47	/mo	9020 LED Architectural - Frozen	26.64	/mo	4.17	1251
1252					9200 LED Architectural - Frozen	25.08	/mo	9200 LED Architectural - Frozen	29.74	/mo	4.66	1252
1253					9900 LED Architectural - Frozen	13.54	/mo	9900 LED Architectural - Frozen	16.04	/mo	2.50	1253
1254					10000 LED Architectural - Frozen	20.99	/mo	10000 LED Architectural - Frozen	24.88	/mo	3.89	1254
1255					10000 LED Architectural - Frozen	12.99	/mo	10000 LED Architectural - Frozen	15.39	/mo	2.40	1255
1256					10600 LED Architectural - Frozen	22.10	/mo	10600 LED Architectural - Frozen	26.20	/mo	4.10	1256
1257					11100 LED Architectural - Frozen	12.50	/mo	11100 LED Architectural - Frozen	14.81	/mo	2.31	1257
1258					11500 LED Architectural - Frozen	12.89	/mo	11500 LED Architectural - Frozen	15.27	/mo	2.38	1258
1259					12300 LED Architectural - Frozen	24.96	/mo	12300 LED Architectural - Frozen	29.59	/mo	4.63	1259
1260					12900 LED Architectural - Frozen	21.85	/mo	12900 LED Architectural - Frozen	25.90	/mo	4.05	1260
1261					13260 LED Architectural - Frozen	26.55	/mo	13260 LED Architectural - Frozen	31.48	/mo	4.93	1261
1262					13620 LED Architectural - Frozen	27.91	/mo	13620 LED Architectural - Frozen	33.09	/mo	5.18	1262
1263					14000 LED Architectural - Frozen	25.54	/mo	14000 LED Architectural - Frozen	30.28	/mo	4.74	1263
1264					15000 LED Architectural - Frozen	24.42	/mo	15000 LED Architectural - Frozen	28.95	/mo	4.53	1264
1265					15400 LED Architectural - Frozen	24.69	/mo	15400 LED Architectural - Frozen	29.27	/mo	4.58	1265
1266					18300 LED Architectural - Frozen	15.80	/mo	18300 LED Architectural - Frozen	18.73	/mo	2.93	1266
1267					19200 LED Architectural - Frozen	26.32	/mo	19200 LED Architectural - Frozen	31.21	/mo	4.89	1267
1268					20000 LED Architectural - Frozen	26.32	/mo	20000 LED Architectural - Frozen	31.21	/mo	4.89	1268

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1269	E-58	Street Lighting Service	Rate	Sum & Win	20300 LED Architectural - Frozen	$ 16.82	/mo	20300 LED Architectural - Frozen	$ 19.94	/mo	$ 3.12	1269
1270	(continued)				21000 LED Architectural - Frozen	24.26	/mo	21000 LED Architectural - Frozen	28.76	/mo	4.50	1270
1271					6200 IND Cobra - Frozen	10.32	/mo	6200 IND Cobra - Frozen	12.22	/mo	1.90	1271
1272					6400 IND Cobra - Frozen	8.79	/mo	6400 IND Cobra - Frozen	10.41	/mo	1.62	1272
1273					8000 IND Cobra - Frozen	10.26	/mo	8000 IND Cobra - Frozen	12.15	/mo	1.89	1273
1274					8400 IND Cobra - Frozen	9.50	/mo	8400 IND Cobra - Frozen	11.25	/mo	1.75	1274
1275					10200 IND Cobra - Frozen	10.23	/mo	10200 IND Cobra - Frozen	12.12	/mo	1.89	1275
1276					13000 IND Cobra - Frozen	11.26	/mo	13000 IND Cobra - Frozen	13.34	/mo	2.08	1276
1277					15250 IND Cobra - Frozen	13.58	/mo	15250 IND Cobra - Frozen	16.09	/mo	2.51	1277
1278					22500 IND Cobra - Frozen	18.17	/mo	22500 IND Cobra - Frozen	21.54	/mo	3.37	1278
1279					3500 IND Cobra Gray/Bronze - Frozen	10.28	/mo	3500 IND Cobra Gray/Bronze - Frozen	12.18	/mo	1.90	1279
1280					6000 LED Cobra - Frozen	16.70	/mo	6000 LED Cobra - Frozen	19.79	/mo	3.09	1280
1281					8700 LED Cobra - Frozen	18.78	/mo	8700 LED Cobra - Frozen	22.26	/mo	3.48	1281
1282					9600 LED Cobra - Frozen	19.98	/mo	9600 LED Cobra - Frozen	23.69	/mo	3.71	1282
1283					11600 LED-B Cobra - Frozen	18.64	/mo	11600 LED-B Cobra - Frozen	22.10	/mo	3.46	1283
1284					3300 LED Cobra Gray/Bronze - Frozen	8.82	/mo	3300 LED Cobra Gray/Bronze - Frozen	10.44	/mo	1.62	1284
1285					5300 LED Cobra Gray/Bronze - Frozen	10.24	/mo	5300 LED Cobra Gray/Bronze - Frozen	12.13	/mo	1.89	1285
1286					8300 LED Cobra Gray/Bronze - Frozen	13.27	/mo	8300 LED Cobra Gray/Bronze - Frozen	15.72	/mo	2.45	1286
1287					10500 LED Cobra Gray/Bronze - Frozen	14.77	/mo	10500 LED Cobra Gray/Bronze - Frozen	17.50	/mo	2.73	1287
1288					20000 LED Cobra Gray/Bronze - Frozen	25.67	/mo	20000 LED Cobra Gray/Bronze - Frozen	30.44	/mo	4.77	1288
1289					5300 LED Decorative Transit - Frozen	27.86	/mo	5300 LED Decorative Transit - Frozen	33.03	/mo	5.17	1289
1290					8300 LED Decorative Transit - Frozen	29.83	/mo	8300 LED Decorative Transit - Frozen	35.37	/mo	5.54	1290
1291					8147 LED Decorative Transit - Frozen	35.03	/mo	8147 LED Decorative Transit - Frozen	41.54	/mo	6.51	1291
1292					9522 LED Decorative Transit - Frozen	35.40	/mo	9522 LED Decorative Transit - Frozen	41.98	/mo	6.58	1292
1293					10500 LED Decorative Transit - Frozen	32.02	/mo	10500 LED Decorative Transit - Frozen	37.97	/mo	5.95	1293
1294					14896 LED Decorative Transit - Frozen	39.16	/mo	14896 LED Decorative Transit - Frozen	46.44	/mo	7.28	1294
1295					8147 LED Decorative Transit Double - Frozen	63.41	/mo	8147 LED Decorative Transit Double - Frozen	75.21	/mo	11.80	1295
1296					9522 LED Decorative Transit Double - Frozen	63.34	/mo	9522 LED Decorative Transit Double - Frozen	75.13	/mo	11.79	1296
1297					14896 LED Decorative Transit Double - Frozen	69.22	/mo	14896 LED Decorative Transit Double - Frozen	82.11	/mo	12.89	1297
1298					6000 IND Decorative Transit Copper - Frozen	18.48	/mo	6000 IND Decorative Transit Copper - Frozen	21.91	/mo	3.43	1298
1299					8000 IND Decorative Transit Gray/Black - Frozen	14.56	/mo	8000 IND Decorative Transit Gray/Black - Frozen	17.25	/mo	2.69	1299
1300					4350 LED Decorative Transit Gray/Black - Frozen	13.20	/mo	4350 LED Decorative Transit Gray/Black - Frozen	15.64	/mo	2.44	1300
1301					14470 LED Flood - Frozen	23.44	/mo	14470 LED Flood - Frozen	27.79	/mo	4.35	1301
1302					16000 LED Flood - Frozen	22.70	/mo	16000 LED Flood - Frozen	26.91	/mo	4.21	1302
1303					8678 LED Pendant - Frozen	25.82	/mo	8678 LED Pendant - Frozen	30.61	/mo	4.79	1303
1304					13964 LED Pendant - Frozen	27.27	/mo	13964 LED Pendant - Frozen	32.33	/mo	5.06	1304
1305					4350 LED Post Top - Frozen	13.15	/mo	4350 LED Post Top - Frozen	15.58	/mo	2.43	1305
1306					6400 LED Post Top - Frozen	13.15	/mo	6400 LED Post Top - Frozen	15.58	/mo	2.43	1306
1307					6600 LED Post Top - Frozen	13.06	/mo	6600 LED Post Top - Frozen	15.48	/mo	2.42	1307
1308					3300 LED Roadway - Frozen	9.27	/mo	3300 LED Roadway - Frozen	10.98	/mo	1.71	1308
1309					3800 LED Roadway - Frozen	7.09	/mo	3800 LED Roadway - Frozen	8.39	/mo	1.30	1309
1310					3900 LED Roadway - Frozen	8.99	/mo	3900 LED Roadway - Frozen	10.65	/mo	1.66	1310
1311					4100 LED Roadway - Frozen	9.36	/mo	4100 LED Roadway - Frozen	11.09	/mo	1.73	1311
1312					4800 LED Roadway - Frozen	7.60	/mo	4800 LED Roadway - Frozen	9.00	/mo	1.40	1312
1313					5000 LED Roadway - Frozen	8.93	/mo	5000 LED Roadway - Frozen	10.58	/mo	1.65	1313
1314					5100 LED Roadway - Frozen	9.49	/mo	5100 LED Roadway - Frozen	11.24	/mo	1.75	1314

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1315	E-58	Street Lighting Service	Rate	Sum & Win	5300 LED Roadway - Frozen	$ 9.78	/mo	5300 LED Roadway - Frozen	$ 11.58	/mo	$ 1.80	1315
1316	(continued)				8200 LED Roadway - Frozen	9.52	/mo	8200 LED Roadway - Frozen	11.28	/mo	1.76	1316
1317					8200 LED Roadway - Frozen	11.13	/mo	8200 LED Roadway - Frozen	13.19	/mo	2.06	1317
1318					8300 LED Roadway - Frozen	11.50	/mo	8300 LED Roadway - Frozen	13.62	/mo	2.12	1318
1319					8500 LED Roadway - Frozen	10.95	/mo	8500 LED Roadway - Frozen	12.97	/mo	2.02	1319
1320					9900 LED Roadway - Frozen	13.04	/mo	9900 LED Roadway - Frozen	15.45	/mo	2.41	1320
1321					10000 LED Roadway - Frozen	12.49	/mo	10000 LED Roadway - Frozen	14.80	/mo	2.31	1321
1322					11100 LED Roadway - Frozen	11.78	/mo	11100 LED Roadway - Frozen	13.96	/mo	2.18	1322
1323					11500 LED Roadway - Frozen	12.39	/mo	11500 LED Roadway - Frozen	14.68	/mo	2.29	1323
1324					18300 LED Roadway - Frozen	14.92	/mo	18300 LED Roadway - Frozen	17.68	/mo	2.76	1324
1325					19200 LED Roadway - Frozen	18.72	/mo	19200 LED Roadway - Frozen	22.19	/mo	3.47	1325
1326					20000 LED Roadway - Frozen	18.72	/mo	20000 LED Roadway - Frozen	22.19	/mo	3.47	1326
1327					20300 LED Roadway - Frozen	15.94	/mo	20300 LED Roadway - Frozen	18.89	/mo	2.95	1327
1328					21000 LED Roadway - Frozen	16.66	/mo	21000 LED Roadway - Frozen	19.75	/mo	3.09	1328
1329					4000 Inc - Frozen	10.32	/mo	4000 Inc - Frozen	12.22	/mo	1.90	1329
1330					7000 Mv - Frozen	13.37	/mo	7000 Mv - Frozen	15.84	/mo	2.47	1330
1331					11000 MV - Frozen	16.74	/mo	11000 MV - Frozen	19.84	/mo	3.10	1331
1332					20000 Mv - Frozen	26.29	/mo	20000 Mv - Frozen	31.17	/mo	4.88	1332
1333					9500 HPS Acorn- Frozen	28.54	/mo	9500 HPS Acorn- Frozen	33.84	/mo	5.30	1333
1334					16000 HPS Acorn- Frozen	31.69	/mo	16000 HPS Acorn- Frozen	37.58	/mo	5.89	1334
1335					9500 HPS Architectural - Frozen	16.22	/mo	9500 HPS Architectural - Frozen	19.22	/mo	3.00	1335
1336					16000 HPS Architectural - Frozen	19.36	/mo	16000 HPS Architectural - Frozen	22.95	/mo	3.59	1336
1337					30000 HPS Architectural - Frozen	22.48	/mo	30000 HPS Architectural - Frozen	26.65	/mo	4.17	1337
1338					50000 HPS Architectural - Frozen	27.74	/mo	50000 HPS Architectural - Frozen	32.89	/mo	5.15	1338
1339					14000 MH Architectural - Frozen	22.70	/mo	14000 MH Architectural - Frozen	26.91	/mo	4.21	1339
1340					21000 MH Architectural - Frozen	25.77	/mo	21000 MH Architectural - Frozen	30.56	/mo	4.79	1340
1341					36000 MH Architectural - Frozen	32.22	/mo	36000 MH Architectural - Frozen	38.21	/mo	5.99	1341
1342					8000 LPS Architectural - Frozen	23.59	/mo	8000 LPS Architectural - Frozen	27.97	/mo	4.38	1342
1343					13500 LPS Architectural - Frozen	27.81	/mo	13500 LPS Architectural - Frozen	32.98	/mo	5.17	1343
1344					22500 LPS Architectural - Frozen	31.77	/mo	22500 LPS Architectural - Frozen	37.67	/mo	5.90	1344
1345					33000 LPS Architectural - Frozen	38.21	/mo	33000 LPS Architectural - Frozen	45.31	/mo	7.10	1345
1346					5800 HPS Cobra/Roadway - Frozen	9.21	/mo	5800 HPS Cobra/Roadway - Frozen	10.91	/mo	1.70	1346
1347					9500 HPS Cobra/Roadway - Frozen	10.84	/mo	9500 HPS Cobra/Roadway - Frozen	12.84	/mo	2.00	1347
1348					16000 HPS Cobra/Roadway - Frozen	13.58	/mo	16000 HPS Cobra/Roadway - Frozen	16.09	/mo	2.51	1348
1349					30000 HPS Cobra/Roadway - Frozen	16.38	/mo	30000 HPS Cobra/Roadway - Frozen	19.41	/mo	3.03	1349
1350					50000 HPS Cobra/Roadway - Frozen	22.22	/mo	50000 HPS Cobra/Roadway - Frozen	26.34	/mo	4.12	1350
1351					14000 MH Cobra/Roadway - Frozen	15.79	/mo	14000 MH Cobra/Roadway - Frozen	18.71	/mo	2.92	1351
1352					21000 MH Cobra/Roadway - Frozen	18.45	/mo	21000 MH Cobra/Roadway - Frozen	21.87	/mo	3.42	1352
1353					36000 MH Cobra/Roadway - Frozen	24.30	/mo	36000 MH Cobra/Roadway - Frozen	28.81	/mo	4.51	1353
1354					8000 FL Cobra/Roadway - Frozen	18.15	/mo	8000 FL Cobra/Roadway - Frozen	21.51	/mo	3.36	1354
1355					9500 HPS Decorative Transit - Frozen	39.13	/mo	9500 HPS Decorative Transit - Frozen	46.41	/mo	7.28	1355
1356					16000 HPS Decorative Transit - Frozen	38.91	/mo	16000 HPS Decorative Transit - Frozen	46.15	/mo	7.24	1356
1357					30000 HPS Decorative Transit - Frozen	44.80	/mo	30000 HPS Decorative Transit - Frozen	53.13	/mo	8.33	1357
1358					30000 HPS Flood - Frozen	21.74	/mo	30000 HPS Flood - Frozen	25.77	/mo	4.03	1358
1359					50000 HPS Flood - Frozen	26.97	/mo	50000 HPS Flood - Frozen	31.98	/mo	5.01	1359
1360					21000 MH Flood - Frozen	23.20	/mo	21000 MH Flood - Frozen	27.51	/mo	4.31	1360
1361					36000 MH Flood - Frozen	28.30	/mo	36000 MH Flood - Frozen	33.56	/mo	5.26	1361
1362					8000 FL Post Top Colonial Gray - Frozen	19.56	/mo	8000 FL Post Top Colonial Gray - Frozen	23.19	/mo	3.63	1362
1363					9500 HPS Post Top Colonial Gray- Frozen	11.19	/mo	9500 HPS Post Top Colonial Gray- Frozen	13.26	/mo	2.07	1363
1364					9500 HPS Post Top Colonial Black- Frozen	12.88	/mo	9500 HPS Post Top Colonial Black- Frozen	15.26	/mo	2.38	1364
1365					9500 HPS Decorative Post Top - Frozen	34.25	/mo	9500 HPS Decorative Post Top - Frozen	40.62	/mo	6.37	1365
1366					4300 LED Architectural/RW Bronze - Frozen	10.34	/mo	4300 LED Architectural/RW Bronze - Frozen	12.25	/mo	1.91	1366
1367					20100 LED Architectural/RW Bronze - Frozen	16.51	/mo	20100 LED Architectural/RW Bronze - Frozen	19.57	/mo	3.06	1367
1368					21000 LED Architectural/RW Bronze - Frozen	24.11	/mo	21000 LED Architectural/RW Bronze - Frozen	28.59	/mo	4.48	1368

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1369	E-58	Street Lighting Service	Rate	Sum & Win	20100 LED Cobra/Gray - Frozen	$ 15.61	/mo	20100 LED Cobra/Gray - Frozen	$ 18.50	/mo	$ 2.89	1369
1370	(continued)				21000 LED Cobra/Gray - Frozen	16.35	/mo	21000 LED Cobra/Gray - Frozen	19.38	/mo	3.03	1370
1371					4300 LED Roadway/Gray - Frozen	9.79	/mo	4300 LED Roadway/Gray - Frozen	11.60	/mo	1.81	1371
1372					5400 LED Roadway/Gray - Frozen	9.69	/mo	5400 LED Roadway/Gray - Frozen	11.48	/mo	1.79	1372
1373					8600 LED Roadway - Frozen	11.36	/mo	8600 LED Roadway - Frozen	13.46	/mo	2.10	1373
1374					6400 LED Post Top/Salem Black - Frozen	12.49	/mo	6400 LED Post Top/Salem Black - Frozen	14.80	/mo	2.31	1374
1375					4350 LED Post Top/Salem Black - Frozen	12.59	/mo	4350 LED Post Top/Salem Black - Frozen	14.92	/mo	2.33	1375
1376					5600 LED Town & Country/Gray - Frozen	9.16	/mo	5600 LED Town & Country/Gray - Frozen	10.85	/mo	1.69	1376
1377					5600 LED Town & Country/Black - Frozen	9.16	/mo	5600 LED Town & Country/Black - Frozen	10.85	/mo	1.69	1377
1378					3270 Decorative Transit/Single - Frozen	38.81	/mo	3270 Decorative Transit/Single - Frozen	46.03	/mo	7.22	1378
1379					3408 LED RW architectural Bronze - Frozen	8.38	/mo	3408 LED RW Architectural Bronze - Frozen	9.92	/mo	1.54	1379
1380					4800 LED RW Architectural Bronze - Frozen	8.76	/mo	4800 LED RW Architectural Bronze - Frozen	10.37	/mo	1.61	1380
1381					4900 LED RW Architectural Bronze - Frozen	8.61	/mo	4900 LED RW Architectural Bronze - Frozen	10.20	/mo	1.59	1381
1382					7810 LED RW Architectural Bronze - Frozen	11.21	/mo	7810 LED RW Architectural Bronze - Frozen	13.28	/mo	2.07	1382
1383					8165 LED RW Architectural Bronze - Frozen	11.20	/mo	8165 LED RW Architectural Bronze - Frozen	13.27	/mo	2.07	1383
1384					11000 LED RW Architectural Bronze - Frozen	12.19	/mo	11000 LED RW Architectural Bronze - Frozen	14.44	/mo	2.25	1384
1385					11500 LED RW Architectural Bronze - Frozen	12.15	/mo	11500 LED RW Architectural Bronze - Frozen	14.40	/mo	2.25	1385
1386					3408 LED Cobra Roadway Gray - Frozen	7.75	/mo	3408 LED Cobra Roadway Gray - Frozen	9.18	/mo	1.43	1386
1387					4800 LED Cobra Roadway Gray - Frozen	8.13	/mo	4800 LED Cobra Roadway Gray - Frozen	9.63	/mo	1.50	1387
1388					4900 LED Cobra Roadway Gray - Frozen	8.18	/mo	4900 LED Cobra Roadway Gray - Frozen	9.69	/mo	1.51	1388
1389					7810 LED Cobra Roadway Gray - Frozen	10.41	/mo	7810 LED Cobra Roadway Gray - Frozen	12.33	/mo	1.92	1389
1390					8165 LED Cobra Roadway Gray - Frozen	10.60	/mo	8165 LED Cobra Roadway Gray - Frozen	12.56	/mo	1.96	1390
1391					11000 LED Cobra Roadway Gray - Frozen	11.39	/mo	11000 LED Cobra Roadway Gray - Frozen	13.49	/mo	2.10	1391
1392					11500 LED Cobra Roadway Gray - Frozen	11.29	/mo	11500 LED Cobra Roadway Gray - Frozen	13.38	/mo	2.09	1392
1393					14500 LED Flood - Frozen	14.71	/mo	14500 LED Flood - Frozen	17.43	/mo	2.72	1393
1394												1394
1395					**FIXTURES (Investment by Others)**			**FIXTURES (Investment by Others)**				1395
1396					3835 LED Acorn - Frozen	$ 7.43	/mo	3835 LED Acorn - Frozen	$ 8.80	/mo	$ 1.37	1396
1397					4796 LED Acorn - Frozen	6.33	/mo	4796 LED Acorn - Frozen	7.49	/mo	1.16	1397
1398					5003 LED Acorn - Frozen	8.53	/mo	5003 LED Acorn - Frozen	10.10	/mo	1.57	1398
1399					5904 LED Acorn - Frozen	8.42	/mo	5904 LED Acorn - Frozen	9.97	/mo	1.55	1399
1400					6000 IND Acorn - Frozen	5.03	/mo	6000 IND Acorn - Frozen	5.95	/mo	0.92	1400
1401					6200 IND Architectural - Frozen	3.85	/mo	6200 IND Architectural - Frozen	4.55	/mo	0.70	1401
1402					8400 IND Architectural - Frozen	4.27	/mo	8400 IND Architectural - Frozen	5.05	/mo	0.78	1402
1403					10200 IND Architectural - Frozen	4.89	/mo	10200 IND Architectural - Frozen	5.78	/mo	0.89	1403
1404					13000 IND Architectural - Frozen	5.81	/mo	13000 IND Architectural - Frozen	6.87	/mo	1.06	1404
1405					20500 IND Architectural - Frozen	7.22	/mo	20500 IND Architectural - Frozen	8.55	/mo	1.33	1405
1406					22500 IND Architectural - Frozen	9.09	/mo	22500 IND Architectural - Frozen	10.76	/mo	1.67	1406
1407					3300 LED Architectural - Frozen	3.71	/mo	3300 LED Architectural - Frozen	4.38	/mo	0.67	1407
1408					3800 LED Architectural - Frozen	2.86	/mo	3800 LED Architectural - Frozen	3.37	/mo	0.51	1408
1409					3900 LED Architectural - Frozen	3.44	/mo	3900 LED Architectural - Frozen	4.06	/mo	0.62	1409
1410					4050 LED Architectural - Frozen	6.39	/mo	4050 LED Architectural - Frozen	7.56	/mo	1.17	1410
1411					4100 LED Architectural - Frozen	3.81	/mo	4100 LED Architectural - Frozen	4.50	/mo	0.69	1411
1412					4800 LED Architectural - Frozen	3.20	/mo	4800 LED Architectural - Frozen	3.78	/mo	0.58	1412
1413					5000 LED Architectural - Frozen	3.55	/mo	5000 LED Architectural - Frozen	4.19	/mo	0.64	1413
1414					5100 LED Architectural - Frozen	4.10	/mo	5100 LED Architectural - Frozen	4.84	/mo	0.74	1414
1415					5300 LED Architectural - Frozen	4.39	/mo	5300 LED Architectural - Frozen	5.19	/mo	0.80	1415
1416					5800 LED Architectural - Frozen	5.05	/mo	5800 LED Architectural - Frozen	5.97	/mo	0.92	1416
1417					5890 LED Architectural - Frozen	7.50	/mo	5890 LED Architectural - Frozen	8.88	/mo	1.38	1417
1418					6000 LED Architectural - Frozen	6.39	/mo	6000 LED Architectural - Frozen	7.56	/mo	1.17	1418
1419					6000 LED Architectural - Frozen	6.85	/mo	6000 LED Architectural - Frozen	8.11	/mo	1.26	1419
1420					6400 LED Architectural - Frozen	5.00	/mo	6400 LED Architectural - Frozen	5.91	/mo	0.91	1420
1421					6810 LED Architectural - Frozen	7.35	/mo	6810 LED Architectural - Frozen	8.70	/mo	1.35	1421
1422					7100 LED Architectural - Frozen	6.66	/mo	7100 LED Architectural - Frozen	7.88	/mo	1.22	1422

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1423	E-58	Street Lighting Service	Rate	Sum & Win	7400 LED Architectural - Frozen	$ 6.21	/mo	7400 LED Architectural - Frozen	$ 7.35	/mo	$ 1.14	1423
1424	(continued)				7500 LED Architectural - Frozen	7.03	/mo	7500 LED Architectural - Frozen	8.32	/mo	1.29	1424
1425					7700 LED Architectural - Frozen	6.88	/mo	7700 LED Architectural - Frozen	8.14	/mo	1.26	1425
1426					8200 LED Architectural - Frozen	4.87	/mo	8200 LED Architectural - Frozen	5.76	/mo	0.89	1426
1427					8200 LED Architectural - Frozen	5.37	/mo	8200 LED Architectural - Frozen	6.35	/mo	0.98	1427
1428					8300 LED Architectural - Frozen	6.41	/mo	8300 LED Architectural - Frozen	7.59	/mo	1.18	1428
1429					8300 LED Architectural - Frozen	5.79	/mo	8300 LED Architectural - Frozen	6.85	/mo	1.06	1429
1430					8500 LED Architectural - Frozen	5.19	/mo	8500 LED Architectural - Frozen	6.14	/mo	0.95	1430
1431					9020 LED Architectural - Frozen	9.28	/mo	9020 LED Architectural - Frozen	10.99	/mo	1.71	1431
1432					9200 LED Architectural - Frozen	7.15	/mo	9200 LED Architectural - Frozen	8.46	/mo	1.31	1432
1433					9900 LED Architectural - Frozen	6.70	/mo	9900 LED Architectural - Frozen	7.93	/mo	1.23	1433
1434					10000 LED Architectural - Frozen	7.80	/mo	10000 LED Architectural - Frozen	9.23	/mo	1.43	1434
1435					10000 LED Architectural - Frozen	6.15	/mo	10000 LED Architectural - Frozen	7.28	/mo	1.13	1435
1436					10600 LED Architectural - Frozen	8.90	/mo	10600 LED Architectural - Frozen	10.54	/mo	1.64	1436
1437					11100 LED Architectural - Frozen	5.95	/mo	11100 LED Architectural - Frozen	7.04	/mo	1.09	1437
1438					11500 LED Architectural - Frozen	6.05	/mo	11500 LED Architectural - Frozen	7.16	/mo	1.11	1438
1439					12300 LED Architectural - Frozen	8.67	/mo	12300 LED Architectural - Frozen	10.27	/mo	1.60	1439
1440					12900 LED Architectural - Frozen	8.64	/mo	12900 LED Architectural - Frozen	10.23	/mo	1.59	1440
1441					13260 LED Architectural - Frozen	11.87	/mo	13260 LED Architectural - Frozen	14.06	/mo	2.19	1441
1442					13620 LED Architectural - Frozen	9.05	/mo	13620 LED Architectural - Frozen	10.72	/mo	1.67	1442
1443					14000 LED Architectural - Frozen	10.85	/mo	14000 LED Architectural - Frozen	12.85	/mo	2.00	1443
1444					15000 LED Architectural - Frozen	9.74	/mo	15000 LED Architectural - Frozen	11.54	/mo	1.80	1444
1445					15400 LED Architectural - Frozen	10.01	/mo	15400 LED Architectural - Frozen	11.86	/mo	1.85	1445
1446					18300 LED Architectural - Frozen	8.05	/mo	18300 LED Architectural - Frozen	9.53	/mo	1.48	1446
1447					19200 LED Architectural - Frozen	13.11	/mo	19200 LED Architectural - Frozen	15.53	/mo	2.42	1447
1448					20000 LED Architectural - Frozen	13.11	/mo	20000 LED Architectural - Frozen	15.53	/mo	2.42	1448
1449					20300 LED Architectural - Frozen	9.07	/mo	20300 LED Architectural - Frozen	10.74	/mo	1.67	1449
1450					21000 LED Architectural - Frozen	11.05	/mo	21000 LED Architectural - Frozen	13.09	/mo	2.04	1450
1451					6200 IND Cobra - Frozen	3.69	/mo	6200 IND Cobra - Frozen	4.36	/mo	0.67	1451
1452					6400 IND Cobra - Frozen	3.70	/mo	6400 IND Cobra - Frozen	4.37	/mo	0.67	1452
1453					8000 IND Cobra - Frozen	3.96	/mo	8000 IND Cobra - Frozen	4.68	/mo	0.72	1453
1454					8400 IND Cobra - Frozen	4.15	/mo	8400 IND Cobra - Frozen	4.90	/mo	0.75	1454
1455					10200 IND Cobra - Frozen	4.71	/mo	10200 IND Cobra - Frozen	5.57	/mo	0.86	1455
1456					13000 IND Cobra - Frozen	5.61	/mo	13000 IND Cobra - Frozen	6.64	/mo	1.03	1456
1457					15250 IND Cobra - Frozen	7.10	/mo	15250 IND Cobra - Frozen	8.40	/mo	1.30	1457
1458					22500 IND Cobra - Frozen	8.87	/mo	22500 IND Cobra - Frozen	10.50	/mo	1.63	1458
1459					3500 IND Cobra Gray/Bronze - Frozen	3.20	/mo	3500 IND Cobra Gray/Bronze - Frozen	3.78	/mo	0.58	1459
1460					6000 LED Cobra - Frozen	5.02	/mo	6000 LED Cobra - Frozen	5.94	/mo	0.92	1460
1461					8700 LED Cobra - Frozen	6.40	/mo	8700 LED Cobra - Frozen	7.57	/mo	1.17	1461
1462					9600 LED Cobra - Frozen	6.90	/mo	9600 LED Cobra - Frozen	8.17	/mo	1.27	1462
1463					11600 LED-B Cobra - Frozen	7.29	/mo	11600 LED-B Cobra - Frozen	8.63	/mo	1.34	1463
1464					3300 LED Cobra Gray/Bronze - Frozen	2.73	/mo	3300 LED Cobra Gray/Bronze - Frozen	3.22	/mo	0.49	1464
1465					5300 LED Cobra Gray/Bronze - Frozen	3.47	/mo	5300 LED Cobra Gray/Bronze - Frozen	4.10	/mo	0.63	1465
1466					8300 LED Cobra Gray/Bronze - Frozen	4.84	/mo	8300 LED Cobra Gray/Bronze - Frozen	5.72	/mo	0.88	1466
1467					10500 LED Cobra Gray/Bronze - Frozen	5.57	/mo	10500 LED Cobra Gray/Bronze - Frozen	6.59	/mo	1.02	1467
1468					20000 LED Cobra Gray/Bronze - Frozen	10.06	/mo	20000 LED Cobra Gray/Bronze - Frozen	11.92	/mo	1.86	1468
1469					5300 LED Decorative Transit - Frozen	5.99	/mo	5300 LED Decorative Transit - Frozen	7.09	/mo	1.10	1469
1470					8300 LED Decorative Transit - Frozen	6.83	/mo	8300 LED Decorative Transit - Frozen	8.08	/mo	1.25	1470
1471					8147 LED Decorative Transit - Frozen	11.13	/mo	8147 LED Decorative Transit - Frozen	13.19	/mo	2.06	1471
1472					9522 LED Decorative Transit - Frozen	11.84	/mo	9522 LED Decorative Transit - Frozen	14.03	/mo	2.19	1472
1473					10500 LED Decorative Transit - Frozen	8.35	/mo	10500 LED Decorative Transit - Frozen	9.89	/mo	1.54	1473

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1474	E-58	Street Lighting Service	Rate	Sum & Win	14896 LED Decorative Transit - Frozen	$ 14.00	/mo	14896 LED Decorative Transit - Frozen	$ 16.59	/mo	$ 2.59	1474
1475	(continued)				8147 LED Decorative Transit Double - Frozen	18.57	/mo	8147 LED Decorative Transit Double - Frozen	22.01	/mo	3.44	1475
1476					9522 LED Decorative Transit Double - Frozen	19.18	/mo	9522 LED Decorative Transit Double - Frozen	22.74	/mo	3.56	1476
1477					14896 LED Decorative Transit Double - Frozen	21.86	/mo	14896 LED Decorative Transit Double - Frozen	25.92	/mo	4.06	1477
1478					6000 IND Decorative Transit Copper - Frozen	4.99	/mo	6000 IND Decorative Transit Copper - Frozen	5.90	/mo	0.91	1478
1479					8000 IND Decorative Transit Gray/Black - Frozen	4.53	/mo	8000 IND Decorative Transit Gray/Black - Frozen	5.35	/mo	0.82	1479
1480					4350 LED Decorative Transit Gray/Black - Frozen	4.35	/mo	4350 LED Decorative Transit Gray/Black - Frozen	5.14	/mo	0.79	1480
1481					14470 LED Flood - Frozen	9.75	/mo	14470 LED Flood - Frozen	11.55	/mo	1.80	1481
1482					16000 LED Flood - Frozen	9.00	/mo	16000 LED Flood - Frozen	10.66	/mo	1.66	1482
1483					8678 LED Pendant - Frozen	8.67	/mo	8678 LED Pendant - Frozen	10.27	/mo	1.60	1483
1484					13964 LED Pendant - Frozen	9.68	/mo	13964 LED Pendant - Frozen	11.46	/mo	1.78	1484
1485					4350 LED Post Top - Frozen	5.57	/mo	4350 LED Post Top - Frozen	6.59	/mo	1.02	1485
1486					6400 LED Post Top - Frozen	5.57	/mo	6400 LED Post Top - Frozen	6.59	/mo	1.02	1486
1487					6600 LED Post Top - Frozen	5.48	/mo	6600 LED Post Top - Frozen	6.48	/mo	1.00	1487
1488					3300 LED Roadway - Frozen	3.51	/mo	3300 LED Roadway - Frozen	4.14	/mo	0.63	1488
1489					3800 LED Roadway - Frozen	2.73	/mo	3800 LED Roadway - Frozen	3.22	/mo	0.49	1489
1490					3900 LED Roadway - Frozen	3.23	/mo	3900 LED Roadway - Frozen	3.81	/mo	0.58	1490
1491					4100 LED Roadway - Frozen	3.60	/mo	4100 LED Roadway - Frozen	4.25	/mo	0.65	1491
1492					4800 LED Roadway - Frozen	3.07	/mo	4800 LED Roadway - Frozen	3.62	/mo	0.55	1492
1493					5000 LED Roadway - Frozen	3.42	/mo	5000 LED Roadway - Frozen	4.04	/mo	0.62	1493
1494					5100 LED Roadway - Frozen	3.98	/mo	5100 LED Roadway - Frozen	4.70	/mo	0.72	1494
1495					5300 LED Roadway - Frozen	4.26	/mo	5300 LED Roadway - Frozen	5.03	/mo	0.77	1495
1496					8200 LED Roadway - Frozen	4.67	/mo	8200 LED Roadway - Frozen	5.52	/mo	0.85	1496
1497					8200 LED Roadway - Frozen	5.23	/mo	8200 LED Roadway - Frozen	6.19	/mo	0.96	1497
1498					8300 LED Roadway - Frozen	5.60	/mo	8300 LED Roadway - Frozen	6.62	/mo	1.02	1498
1499					8500 LED Roadway - Frozen	5.05	/mo	8500 LED Roadway - Frozen	5.97	/mo	0.92	1499
1500					9900 LED Roadway - Frozen	6.56	/mo	9900 LED Roadway - Frozen	7.76	/mo	1.20	1500
1501					10000 LED Roadway - Frozen	6.01	/mo	10000 LED Roadway - Frozen	7.11	/mo	1.10	1501
1502					11100 LED Roadway - Frozen	5.76	/mo	11100 LED Roadway - Frozen	6.81	/mo	1.05	1502
1503					11500 LED Roadway - Frozen	5.92	/mo	11500 LED Roadway - Frozen	7.00	/mo	1.08	1503
1504					18300 LED Roadway - Frozen	7.82	/mo	18300 LED Roadway - Frozen	9.26	/mo	1.44	1504
1505					19200 LED Roadway - Frozen	11.09	/mo	19200 LED Roadway - Frozen	13.14	/mo	2.05	1505
1506					20000 LED Roadway - Frozen	11.09	/mo	20000 LED Roadway - Frozen	13.14	/mo	2.05	1506
1507					20300 LED Roadway - Frozen	8.84	/mo	20300 LED Roadway - Frozen	10.47	/mo	1.63	1507
1508					21000 LED Roadway - Frozen	9.03	/mo	21000 LED Roadway - Frozen	10.69	/mo	1.66	1508
1509					4000 Inc - Frozen	5.77	/mo	4000 Inc - Frozen	6.83	/mo	1.06	1509
1510					7000 Mv - Frozen	7.67	/mo	7000 Mv - Frozen	9.08	/mo	1.41	1510
1511					11000 Mv - Frozen	10.22	/mo	11000 Mv - Frozen	12.11	/mo	1.89	1511
1512					20000 Mv - Frozen	14.90	/mo	20000 Mv - Frozen	17.66	/mo	2.76	1512
1513					9500 HPS Acorn- Frozen	9.73	/mo	9500 HPS Acorn- Frozen	11.52	/mo	1.79	1513
1514					16000 HPS Acorn- Frozen	12.29	/mo	16000 HPS Acorn- Frozen	14.56	/mo	2.27	1514
1515					9500 HPS Architectural - Frozen	7.74	/mo	9500 HPS Architectural - Frozen	9.16	/mo	1.42	1515
1516					16000 HPS Architectural - Frozen	18.94	/mo	16000 HPS Architectural - Frozen	22.45	/mo	3.51	1516
1517					30000 HPS Architectural - Frozen	13.29	/mo	30000 HPS Architectural - Frozen	15.75	/mo	2.46	1517
1518					50000 HPS Architectural - Frozen	19.13	/mo	50000 HPS Architectural - Frozen	22.68	/mo	3.55	1518
1519					14000 MH Architectural - Frozen	12.44	/mo	14000 MH Architectural - Frozen	14.74	/mo	2.30	1519
1520					21000 MH Architectural - Frozen	15.34	/mo	21000 MH Architectural - Frozen	18.18	/mo	2.84	1520
1521					36000 MH Architectural - Frozen	21.10	/mo	36000 MH Architectural - Frozen	25.01	/mo	3.91	1521

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1522	E-58	Street Lighting Service	Rate	Sum & Win	8000 LPS Architectural - Frozen	$ 10.36	/mo	8000 LPS Architectural - Frozen	$ 12.27	/mo	$ 1.91	1522
1523	(continued)				13500 LPS Architectural - Frozen	12.50	/mo	13500 LPS Architectural - Frozen	14.81	/mo	2.31	1523
1524					22500 LPS Architectural - Frozen	15.24	/mo	22500 LPS Architectural - Frozen	18.06	/mo	2.82	1524
1525					33000 LPS Architectural - Frozen	17.95	/mo	33000 LPS Architectural - Frozen	21.28	/mo	3.33	1525
1526					5800 HPS Cobra/Roadway - Frozen	5.45	/mo	5800 HPS Cobra/Roadway - Frozen	6.45	/mo	1.00	1526
1527					9500 HPS Cobra/Roadway - Frozen	6.67	/mo	9500 HPS Cobra/Roadway - Frozen	7.89	/mo	1.22	1527
1528					16000 HPS Cobra/Roadway - Frozen	9.31	/mo	16000 HPS Cobra/Roadway - Frozen	11.03	/mo	1.72	1528
1529					30000 HPS Cobra/Roadway - Frozen	12.10	/mo	30000 HPS Cobra/Roadway - Frozen	14.34	/mo	2.24	1529
1530					50000 HPS Cobra/Roadway - Frozen	17.27	/mo	50000 HPS Cobra/Roadway - Frozen	20.47	/mo	3.20	1530
1531					14000 MH Cobra/Roadway - Frozen	10.76	/mo	14000 MH Cobra/Roadway - Frozen	12.75	/mo	1.99	1531
1532					21000 MH Cobra/Roadway - Frozen	13.39	/mo	21000 MH Cobra/Roadway - Frozen	15.87	/mo	2.48	1532
1533					36000 MH Cobra/Roadway - Frozen	18.60	/mo	36000 MH Cobra/Roadway - Frozen	22.05	/mo	3.45	1533
1534					8000 FL Cobra/Roadway - Frozen	5.32	/mo	8000 FL Cobra/Roadway - Frozen	6.29	/mo	0.97	1534
1535					9500 HPS Decorative Transit - Frozen	11.71	/mo	9500 HPS Decorative Transit - Frozen	13.87	/mo	2.16	1535
1536					16000 HPS Decorative Transit - Frozen	13.09	/mo	16000 HPS Decorative Transit - Frozen	15.51	/mo	2.42	1536
1537					30000 HPS Decorative Transit - Frozen	16.91	/mo	30000 HPS Decorative Transit - Frozen	20.04	/mo	3.13	1537
1538					30000 HPS Flood - Frozen	13.51	/mo	30000 HPS Flood - Frozen	16.01	/mo	2.50	1538
1539					50000 HPS Flood - Frozen	18.75	/mo	50000 HPS Flood - Frozen	22.23	/mo	3.48	1539
1540					21000 MH Flood - Frozen	14.28	/mo	21000 MH Flood - Frozen	16.92	/mo	2.64	1540
1541					36000 MH Flood - Frozen	19.35	/mo	36000 MH Flood - Frozen	22.94	/mo	3.59	1541
1542					8000 FL Post Top Colonial Gray - Frozen	5.52	/mo	8000 FL Post Top Colonial Gray - Frozen	6.53	/mo	1.01	1542
1543					9500 HPS Post Top Colonial Gray- Frozen	7.01	/mo	9500 HPS Post Top Colonial Gray- Frozen	8.30	/mo	1.29	1543
1544					9500 HPS Post Top Colonial Black- Frozen	7.26	/mo	9500 HPS Post Top Colonial Black- Frozen	8.59	/mo	1.33	1544
1545					9500 HPS Decorative Post Top - Frozen	10.80	/mo	9500 HPS Decorative Post Top - Frozen	12.79	/mo	1.99	1545
1546												1546
1547						$ 3.89	/mo		$ 4.60	/mo	$ 0.71	1547
					4300 LED Architectural/RW Bronze - Frozen			4300 LED Architectural/RW Bronze - Frozen				
1548					20100 LED Architectural/RW Bronze - Frozen	8.60	/mo	20100 LED Architectural/RW Bronze - Frozen	10.18	/mo	1.58	1548
1549					21000 LED Architectural/RW Bronze - Frozen	10.62	/mo	21000 LED Architectural/RW Bronze - Frozen	12.58	/mo	1.96	1549
1550					20100 LED Cobra/Gray - Frozen	8.36	/mo	20100 LED Cobra/Gray - Frozen	9.90	/mo	1.54	1550
1551					21000 LED Cobra/Gray - Frozen	8.56	/mo	21000 LED Cobra/Gray - Frozen	10.14	/mo	1.58	1551
1552					4300 LED Roadway/Gray - Frozen	3.74	/mo	4300 LED Roadway/Gray - Frozen	4.42	/mo	0.68	1552
1553					5400 LED Roadway/Gray - Frozen	4.06	/mo	5400 LED Roadway/Gray - Frozen	4.80	/mo	0.74	1553
1554					8600 LED Roadway - Frozen	5.34	/mo	8600 LED Roadway - Frozen	6.32	/mo	0.98	1554
1555					6400 LED Post Top/Salem Black - Frozen	5.36	/mo	6400 LED Post Top/Salem Black - Frozen	6.34	/mo	0.98	1555
1556					4350 LED Post Top/Salem Black - Frozen	5.46	/mo	4350 LED Post Top/Salem Black - Frozen	6.46	/mo	1.00	1556
1557					5600 LED Town & Country/Gray - Frozen	3.86	/mo	5600 LED Town & Country/Gray - Frozen	4.56	/mo	0.70	1557
1558					5600 LED Town & Country/Black - Frozen	3.86	/mo	5600 LED Town & Country/Black - Frozen	4.56	/mo	0.70	1558
1559					3270 Decorative Transit/Single - Frozen	11.27	/mo	3270 Decorative Transit/Single - Frozen	13.35	/mo	2.08	1559
1560					3408 LED RW architectural Bronze - Frozen	3.02	/mo	3408 LED RW architectural Bronze - Frozen	3.56	/mo	0.54	1560
1561					4800 LED RW Architectural Bronze - Frozen	3.40	/mo	4800 LED RW Architectural Bronze - Frozen	4.01	/mo	0.61	1561
1562					4900 LED RW Architectural Bronze - Frozen	3.36	/mo	4900 LED RW Architectural Bronze - Frozen	3.97	/mo	0.61	1562
1563					7810 LED RW Architectural Bronze - Frozen	4.68	/mo	7810 LED RW Architectural Bronze - Frozen	5.53	/mo	0.85	1563
1564					8165 LED RW Architectural Bronze - Frozen	4.68	/mo	8165 LED RW Architectural Bronze - Frozen	5.53	/mo	0.85	1564
1565					11000 LED RW Architectural Bronze - Frozen	5.64	/mo	11000 LED RW Architectural Bronze - Frozen	6.67	/mo	1.03	1565
1566					11500 LED RW Architectural Bronze - Frozen	5.63	/mo	11500 LED RW Architectural Bronze - Frozen	6.66	/mo	1.03	1566

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1567	E-58 (continued)	Street Lighting Service	Rate	Sum & Win		$ 2.85	/mo		$ 3.36	/mo	$ 0.51	1567
					3408 LED Cobra Roadway Gray - Frozen			3408 LED Cobra Roadway Gray - Frozen				
1568					4800 LED Cobra Roadway Gray - Frozen	3.23	/mo	4800 LED Cobra Roadway Gray - Frozen	3.81	/mo	0.58	1568
1569					4900 LED Cobra Roadway Gray - Frozen	3.24	/mo	4900 LED Cobra Roadway Gray - Frozen	3.82	/mo	0.58	1569
1570					7810 LED Cobra Roadway Gray - Frozen	4.47	/mo	7810 LED Cobra Roadway Gray - Frozen	5.28	/mo	0.81	1570
1571					8165 LED Cobra Roadway Gray - Frozen	4.51	/mo	8165 LED Cobra Roadway Gray - Frozen	5.33	/mo	0.82	1571
1572					11000 LED Cobra Roadway Gray - Frozen	5.42	/mo	11000 LED Cobra Roadway Gray - Frozen	6.41	/mo	0.99	1572
1573					11500 LED Cobra Roadway Gray - Frozen	5.40	/mo	11500 LED Cobra Roadway Gray - Frozen	6.39	/mo	0.99	1573
1574					14500 LED Flood - Frozen	6.31	/mo	14500 LED Flood - Frozen	7.47	/mo	1.16	1574
1575												1575
1576					**Poles (Investment by Company)**			**Poles (Investment by Company)**				1576
1577					12ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	$ 12.84	/mo	12ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	$ 15.21	/mo	$ 2.37	1577
1578					22ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	14.45	/mo	22ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	17.12	/mo	2.67	1578
1579					25ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	15.64	/mo	25ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	18.54	/mo	2.90	1579
1580					30ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	17.96	/mo	30ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	21.29	/mo	3.33	1580
1581					32ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	18.87	/mo	32ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	22.37	/mo	3.50	1581
1582					12ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	13.69	/mo	12ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	16.22	/mo	2.53	1582
1583					22ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	15.73	/mo	22ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	18.64	/mo	2.91	1583
1584					25ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	16.41	/mo	25ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	19.45	/mo	3.04	1584
1585					30ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	19.07	/mo	30ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	22.61	/mo	3.54	1585
1586					32ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	20.34	/mo	32ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	24.11	/mo	3.77	1586
1587					13ft Square Steel Flush Anchor Base - Frozen	14.72	/mo	13ft Square Steel Flush Anchor Base - Frozen	17.44	/mo	2.72	1587
1588					15ft Square Steel Flush Anchor Base - Frozen	13.15	/mo	15ft Square Steel Flush Anchor Base - Frozen	15.58	/mo	2.43	1588
1589					23ft Square Steel Flush Anchor Base - Frozen	15.60	/mo	23ft Square Steel Flush Anchor Base - Frozen	18.49	/mo	2.89	1589
1590					25ft Square Steel Flush Anchor Base - Frozen	17.15	/mo	25ft Square Steel Flush Anchor Base - Frozen	20.33	/mo	3.18	1590
1591					28ft Square Steel Flush Anchor Base - Frozen	19.04	/mo	28ft Square Steel Flush Anchor Base - Frozen	22.57	/mo	3.53	1591
1592					32ft Square Steel Flush Anchor Base - Frozen	18.93	/mo	32ft Square Steel Flush Anchor Base - Frozen	22.44	/mo	3.51	1592
1593					12ft Concrete Flush Anchor Base - Frozen	43.87	/mo	12ft Concrete Flush Anchor Base - Frozen	52.03	/mo	8.16	1593
1594					12ft Fiberglass Flush Anchor Base - Frozen	37.15	/mo	12ft Fiberglass Flush Anchor Base - Frozen	44.06	/mo	6.91	1594
1595					16ft Decorative Transit Pedestrian Anchor Base - Frozen	36.22	/mo	16ft Decorative Transit Pedestrian Anchor Base - Frozen	42.95	/mo	6.73	1595
1596					30ft Transit Anchor Base 6" - Frozen	69.93	/mo	30ft Transit Anchor Base 6" - Frozen	82.95	/mo	13.02	1596
1597					15ft Square Hinged Flush Anchor Base - Frozen	13.92	/mo	15ft Square Hinged Flush Anchor Base - Frozen	16.50	/mo	2.58	1597
1598					19ft Round Hinged Flush Anchor Base - Frozen	12.59	/mo	19ft Round Hinged Flush Anchor Base - Frozen	14.92	/mo	2.33	1598
1599					12ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	12.35	/mo	12ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	14.63	/mo	2.28	1599

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1600	E-58 (continued)	Street Lighting Service	Rate	Sum & Win	22ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	$ 13.97	/mo	22ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	$ 16.55	/mo	$ 2.58	1600
1601					25ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	15.14	/mo	25ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	17.94	/mo	2.80	1601
1602					30ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	17.48	/mo	30ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	20.72	/mo	3.24	1602
1603					32ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	18.37	/mo	32ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	21.78	/mo	3.41	1603
1604					12ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	13.19	/mo	12ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	15.63	/mo	2.44	1604
1605					22ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	14.74	/mo	22ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	17.47	/mo	2.73	1605
1606					25ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	15.91	/mo	25ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	18.86	/mo	2.95	1606
1607					30ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	18.58	/mo	30ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	22.02	/mo	3.44	1607
1608					32ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	19.84	/mo	32ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	23.52	/mo	3.68	1608
1609					32ft Round Steel Pedestal Anchor Base - 3 Bolt - Frozen	22.80	/mo	32ft Round Steel Pedestal Anchor Base - 3 Bolt - Frozen	27.03	/mo	4.23	1609
1610					13ft Square Steel Pedestal Anchor Base - Frozen	14.24	/mo	13ft Square Steel Pedestal Anchor Base - Frozen	16.88	/mo	2.64	1610
1611					15ft Square Steel Pedestal Anchor Base - Frozen	14.56	/mo	15ft Square Steel Pedestal Anchor Base - Frozen	17.25	/mo	2.69	1611
1612					23ft Square Steel Pedestal Anchor Base - Frozen	15.11	/mo	23ft Square Steel Pedestal Anchor Base - Frozen	17.91	/mo	2.80	1612
1613					25ft Square Steel Pedestal Anchor Base - Frozen	16.67	/mo	25ft Square Steel Pedestal Anchor Base - Frozen	19.76	/mo	3.09	1613
1614					28ft Square Steel Pedestal Anchor Base - Frozen	18.52	/mo	28ft Square Steel Pedestal Anchor Base - Frozen	21.95	/mo	3.43	1614
1615					32ft Square Steel Pedestal Anchor Base - Frozen	19.23	/mo	32ft Square Steel Pedestal Anchor Base - Frozen	22.80	/mo	3.57	1615
1616					19ft Round Steel Direct Bury - Frozen	19.43	/mo	19ft Round Steel Direct Bury - Frozen	23.03	/mo	3.60	1616
1617					30ft Round Steel Direct Bury - Frozen	15.17	/mo	30ft Round Steel Direct Bury - Frozen	17.98	/mo	2.81	1617
1618					38ft Round Steel Direct Bury - Frozen	18.51	/mo	38ft Round Steel Direct Bury - Frozen	21.94	/mo	3.43	1618
1619					40ft Round Steel Direct Bury Self Support - Frozen	22.80	/mo	40ft Round Steel Direct Bury Self Support - Frozen	27.03	/mo	4.23	1619
1620					25ft Round Steel Direct Bury Stepped - Frozen	52.45	/mo	25ft Round Steel Direct Bury Stepped - Frozen	62.21	/mo	9.76	1620
1621					32ft Round Steel Direct Bury Stepped - Frozen	55.24	/mo	32ft Round Steel Direct Bury Stepped - Frozen	65.52	/mo	10.28	1621
1622					49ft Round Steel Direct Bury Stepped - Frozen	68.57	/mo	49ft Round Steel Direct Bury Stepped - Frozen	81.34	/mo	12.77	1622
1623					34ft Square Steel Direct Bury 4" - Frozen	16.74	/mo	34ft Square Steel Direct Bury 4" - Frozen	19.84	/mo	3.10	1623
1624					20ft Square Steel Direct Bury 5" - Frozen	15.90	/mo	20ft Square Steel Direct Bury 5" - Frozen	18.84	/mo	2.94	1624
1625					30ft Square Steel Direct Bury 5" - Frozen	16.57	/mo	30ft Square Steel Direct Bury 5" - Frozen	19.64	/mo	3.07	1625
1626					38ft Square Steel Direct Bury 5" - Frozen	17.98	/mo	38ft Square Steel Direct Bury 5" - Frozen	21.31	/mo	3.33	1626
1627					28ft Square Steel Direct Bury 8" - Frozen	30.01	/mo	28ft Square Steel Direct Bury 8" - Frozen	35.59	/mo	5.58	1627
1628					32ft Square Steel Direct Bury 8" - Frozen	31.37	/mo	32ft Square Steel Direct Bury 8" - Frozen	37.20	/mo	5.83	1628
1629					41ft6in Decorative Transit Direct Bury - Frozer	21.60	/mo	41ft6in Decorative Transit Direct Bury - Frozer	25.61	/mo	4.01	1629
1630					47ft Decorative Transit Direct Bury - Frozen	26.91	/mo	47ft Decorative Transit Direct Bury - Frozen	31.91	/mo	5.00	1630
1631					35ft Steel Distribution Pole - Frozen	24.84	/mo	35ft Steel Distribution Pole - Frozen	29.45	/mo	4.61	1631

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1632	E-58 (continued)	Street Lighting Service	Rate	Sum & Win	16ft Decorative Transit Anchor Post Top - Frozen	$ 37.00	/mo	16ft Decorative Transit Anchor Post Top - Frozen	$ 43.88	/mo	$ 6.88	1632
1633						12.83	/mo		15.20	/mo	2.37	1633
					23ft Gray Steel/Fiberglass Post Top - Frozen			23ft Gray Steel/Fiberglass Post Top - Frozen				
1634					23ft Black Steel Post Top - Frozen	14.14	/mo	23ft Black Steel Post Top - Frozen	16.76	/mo	2.62	1634
1635					Existing distribution pole suitable for streetlight use - Frozen	1.56	/mo	Existing distribution pole suitable for streetlight use - Frozen	1.83	/mo	0.27	1635
1636					30 Ft Wood Pole - Frozen	9.44	/mo	30 Ft Wood Pole - Frozen	11.20	/mo	1.76	1636
1637					35 Ft Wood Pole - Frozen	9.44	/mo	35 Ft Wood Pole - Frozen	11.20	/mo	1.76	1637
1638												1638
1639					4ft Flush Anchor Base - Frozen	$ 10.45	/mo	4ft Flush Anchor Base - Frozen	$ 12.38	/mo	$ 1.93	1639
1640					6ft Flush Anchor Base - Frozen	12.47	/mo	6ft Flush Anchor Base - Frozen	14.78	/mo	2.31	1640
1641					8ft Pedestal Anchor Base - Frozen	14.29	/mo	8ft Pedestal Anchor Base - Frozen	16.93	/mo	2.64	1641
1642					4ft 6" Flush Anchor Base" - Frozen	9.91	/mo	4ft 6" Flush Anchor Base" - Frozen	11.74	/mo	1.83	1642
1643												1643
1644					**Poles (Investment by Others)**			**Poles (Investment by Others)**				1644
1645					12ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	$ 1.77	/mo	12ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	$ 2.08	/mo	$ 0.31	1645
1646					22ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	1.99	/mo	22ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	2.34	/mo	0.35	1646
1647					25ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	2.16	/mo	25ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	2.54	/mo	0.38	1647
1648					30ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	2.47	/mo	30ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	2.91	/mo	0.44	1648
1649					32ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	2.50	/mo	32ft Round Steel Flush Anchor Base - 1 Simplex - Frozen	2.95	/mo	0.45	1649
1650					12ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	1.89	/mo	12ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	2.22	/mo	0.33	1650
1651					22ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	2.17	/mo	22ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	2.55	/mo	0.38	1651
1652					25ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	2.26	/mo	25ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	2.66	/mo	0.40	1652
1653					30ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	2.63	/mo	30ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	3.10	/mo	0.47	1653
1654					32ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	2.81	/mo	32ft Round Steel Flush Anchor Base - 2 Simplex - Frozen	3.31	/mo	0.50	1654
1655					13ft Square Steel Flush Anchor Base - Frozen	2.02	/mo	13ft Square Steel Flush Anchor Base - Frozen	2.38	/mo	0.36	1655
1656					15ft Square Steel Flush Anchor Base - Frozen	1.81	/mo	15ft Square Steel Flush Anchor Base - Frozen	2.13	/mo	0.32	1656
1657					23ft Square Steel Flush Anchor Base - Frozen	2.15	/mo	23ft Square Steel Flush Anchor Base - Frozen	2.53	/mo	0.38	1657
1658					25ft Square Steel Flush Anchor Base - Frozen	2.36	/mo	25ft Square Steel Flush Anchor Base - Frozen	2.78	/mo	0.42	1658
1659					28ft Square Steel Flush Anchor Base - Frozen	2.62	/mo	28ft Square Steel Flush Anchor Base - Frozen	3.09	/mo	0.47	1659
1660					32ft Square Steel Flush Anchor Base - Frozen	2.61	/mo	32ft Square Steel Flush Anchor Base - Frozen	3.08	/mo	0.47	1660
1661					12ft Concrete Flush Anchor Base - Frozen	6.04	/mo	12ft Concrete Flush Anchor Base - Frozen	7.15	/mo	1.11	1661
1662					12ft Fiberglass Flush Anchor Base - Frozen	5.11	/mo	12ft Fiberglass Flush Anchor Base - Frozen	6.04	/mo	0.93	1662

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1663	E-58 (continued)	Street Lighting Service	Rate	Sum & Win	16ft Decorative Transit Pedestrian Anchor Base - Frozen	$ 5.00	/mo	16ft Decorative Transit Pedestrian Anchor Base - Frozen	$ 5.91	/mo	$ 0.91	1663
1664					30ft Transit Anchor Base 6" - Frozen	9.63	/mo	30ft Transit Anchor Base 6" - Frozen	11.41	/mo	1.78	1664
1665					15ft Square Hinged Flush Anchor Base - Frozen	1.14	/mo	15ft Square Hinged Flush Anchor Base - Frozen	1.33	/mo	0.19	1665
1666					19ft Round Hinged Flush Anchor Base - Frozen	1.03	/mo	19ft Round Hinged Flush Anchor Base - Frozen	1.20	/mo	0.17	1666
1667					12ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	1.69	/mo	12ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	1.99	/mo	0.30	1667
1668					22ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	1.92	/mo	22ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	2.26	/mo	0.34	1668
1669					25ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	2.09	/mo	25ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	2.46	/mo	0.37	1669
1670					30ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	2.42	/mo	30ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	2.85	/mo	0.43	1670
1671					32ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	2.53	/mo	32ft Round Steel Pedestal Anchor Base - 1 Simplex - Frozen	2.98	/mo	0.45	1671
1672					12ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	1.81	/mo	12ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	2.13	/mo	0.32	1672
1673					22ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	2.02	/mo	22ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	2.38	/mo	0.36	1673
1674					25ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	2.18	/mo	25ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	2.57	/mo	0.39	1674
1675					30ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	2.55	/mo	30ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	3.01	/mo	0.46	1675
1676					32ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	2.73	/mo	32ft Round Steel Pedestal Anchor Base - 2 Simplex - Frozen	3.22	/mo	0.49	1676
1677					32ft Round Steel Pedestal Anchor Base - 3 Bolt - Frozen	3.13	/mo	32ft Round Steel Pedestal Anchor Base - 3 Bolt - Frozen	3.69	/mo	0.56	1677
1678					13ft Square Steel Pedestal Anchor Base - Frozen	1.97	/mo	13ft Square Steel Pedestal Anchor Base - Frozen	2.32	/mo	0.35	1678
1679					15ft Square Steel Pedestal Anchor Base - Frozen	1.99	/mo	15ft Square Steel Pedestal Anchor Base - Frozen	2.34	/mo	0.35	1679
1680					23ft Square Steel Pedestal Anchor Base - Frozen	2.09	/mo	23ft Square Steel Pedestal Anchor Base - Frozen	2.46	/mo	0.37	1680
1681					25ft Square Steel Pedestal Anchor Base - Frozen	2.31	/mo	25ft Square Steel Pedestal Anchor Base - Frozen	2.72	/mo	0.41	1681
1682					28ft Square Steel Pedestal Anchor Base - Frozen	2.55	/mo	28ft Square Steel Pedestal Anchor Base - Frozen	3.01	/mo	0.46	1682
1683					32ft Square Steel Pedestal Anchor Base - Frozen	2.63	/mo	32ft Square Steel Pedestal Anchor Base - Frozen	3.10	/mo	0.47	1683
1684					19ft Round Steel Direct Bury - Frozen	2.68	/mo	19ft Round Steel Direct Bury - Frozen	3.16	/mo	0.48	1684
1685					30ft Round Steel Direct Bury - Frozen	2.81	/mo	30ft Round Steel Direct Bury - Frozen	3.31	/mo	0.50	1685
1686					38ft Round Steel Direct Bury - Frozen	2.88	/mo	38ft Round Steel Direct Bury - Frozen	3.40	/mo	0.52	1686
1687					40ft Round Steel Direct Bury Self Support - Frozen	3.61	/mo	40ft Round Steel Direct Bury Self Support - Frozen	4.26	/mo	0.65	1687

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F)	(G)	(H) Proposed Rates Block	(I)	(J)	(K) Change (I) - (F)	Line No.
1688	E-58 (continued)	Street Lighting Service	Rate	Sum & Win	25ft Round Steel Direct Bury Stepped - Frozen	$ 4.28	/mo	25ft Round Steel Direct Bury Stepped - Frozen	$ 5.06	/mo	$ 0.78	1688
1689					32ft Round Steel Direct Bury Stepped - Frozen	4.51	/mo	32ft Round Steel Direct Bury Stepped - Frozen	5.33	/mo	0.82	1689
1690					49ft Round Steel Direct Bury Stepped - Frozen	9.45	/mo	49ft Round Steel Direct Bury Stepped - Frozen	11.19	/mo	1.74	1690
1691					34ft Square Steel Direct Bury 4" - Frozen	2.90	/mo	34ft Square Steel Direct Bury 4" - Frozen	3.42	/mo	0.52	1691
1692					20ft Square Steel Direct Bury 5" - Frozen	2.63	/mo	20ft Square Steel Direct Bury 5" - Frozen	3.10	/mo	0.47	1692
1693					30ft Square Steel Direct Bury 5" - Frozen	2.73	/mo	30ft Square Steel Direct Bury 5" - Frozen	3.22	/mo	0.49	1693
1694					38ft Square Steel Direct Bury 5" - Frozen	3.12	/mo	38ft Square Steel Direct Bury 5" - Frozen	3.68	/mo	0.56	1694
1695					28ft Square Steel Direct Bury 8" - Frozen	2.44	/mo	28ft Square Steel Direct Bury 8" - Frozen	2.87	/mo	0.43	1695
1696					32ft Square Steel Direct Bury 8" - Frozen	2.57	/mo	32ft Square Steel Direct Bury 8" - Frozen	3.03	/mo	0.46	1696
1697					41ft6in Decorative Transit Direct Bury - Frozer	3.17	/mo	41ft6in Decorative Transit Direct Bury - Frozer	3.74	/mo	0.57	1697
1698					47ft Decorative Transit Direct Bury - Frozen	3.96	/mo	47ft Decorative Transit Direct Bury - Frozen	4.68	/mo	0.72	1698
1699					35ft Steel Distribution Pole - Frozen	3.27	/mo	35ft Steel Distribution Pole - Frozen	3.86	/mo	0.59	1699
1700					16ft Decorative Transit Anchor Post Top - Frozen	5.08	/mo	16ft Decorative Transit Anchor Post Top - Frozen	6.01	/mo	0.93	1700
1701					23ft Gray Steel/Fiberglass Post Top - Frozen	2.11	/mo	23ft Gray Steel/Fiberglass Post Top - Frozen	2.48	/mo	0.37	1701
1702					23ft Black Steel Post Top - Frozen	2.33	/mo	23ft Black Steel Post Top - Frozen	2.74	/mo	0.41	1702
1703					30 Ft Wood Pole - Frozen	1.64	/mo	30 Ft Wood Pole - Frozen	1.95	/mo	0.31	1703
1704					35 Ft Wood Pole - Frozen	1.56	/mo	35 Ft Wood Pole - Frozen	1.85	/mo	0.29	1704
1705					4ft Flush Anchor Base - Frozen	1.44	/mo	4ft Flush Anchor Base - Frozen	1.69	/mo	0.25	1705
1706					6ft Flush Anchor Base - Frozen	2.16	/mo	6ft Flush Anchor Base - Frozen	2.54	/mo	0.38	1706
1707					8ft Pedestal Anchor Base - Frozen	2.49	/mo	8ft Pedestal Anchor Base - Frozen	2.93	/mo	0.44	1707
1708					4ft 6" Flush Anchor Base" - Frozen	1.71	/mo	4ft 6" Flush Anchor Base" - Frozen	2.01	/mo	0.30	1708
1709					Underground Circuit Charges under paving - Frozen	$ 0.16652	per foot	Underground Circuit Charges under paving - Frozen	$ 0.19757	per foot	$ 0.03105	1709
1710					Underground Circuit Charges not under paving - Frozen	0.05877	per foot	Underground Circuit Charges not under paving - Frozen	0.06973	per foot	0.01096	1710
1711												1711
1712					Generation Charge - Frozen	$ 0.06621	/kWh	Generation Charge - Frozen	$ 0.07856	/kWh	$ 0.01235	1712
1713					T&D, RCS,SB Charge - Frozen	0.02682	/kWh	T&D, RCS,SB Charge - Frozen	0.03182	/kWh	0.00500	1713
1714												1714
1715	E-59	Energy Services for Government		Sum & Win								1715
1716		Owned Streetlighting Systems			Service Charge	$ 2.940	/mo	Service Charge	$ 3.480	/mo	$ 0.54	1716
1717					Energy Charge	0.06429	/kWh	Energy Charge	0.07613	/kWh	0.01184	1717
1718	E-67	Municipal Lighting	Rate	Sum & Win								1718
1719		Service -- City of Phoenix			All kWh	$ 0.05481	/kWh	All kWh	$ 0.06493	/kWh	$ 0.01012	1719
1720												1720
1721	E-221	Water Pumping Service	Rate	Sum & Win								1721
1722					BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	1722
1723					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	1723
1724					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	1724
1725					All kW	4.651	/kW	All kW	5.232	/kW	0.581	1725
1726					First 240 kWh	0.10117	/kWh	First 240 kWh	0.13391	/kWh	0.03274	1726
1727					All additional kWh	0.06991	/kWh	All additional kWh	0.09244	/kWh	0.02253	1727
1728			Minimum	Sum & Win								1728
1729					Minimum Basic Service Charge	$ 1.932	/day	Minimum Basic Service Charge	$ 2.418	/day	$ 0.486	1729
1730					Minimum Demand Charge	4.651	/kW	Minimum Demand Charge	5.232	/kW	0.58100	1730

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1731	E-221-8T	Water Pumping Service	Rate	Sum & Win								1731
1732		Time Of Use			BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	1732
1733					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	1733
1734					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	1734
1735					All On-Peak kW	6.414	/kW	All On-Peak kW	7.572	/kW	1.158	1735
1736					All Off-Peak kW	4.171	/kW	All Off-Peak kW	5.534	/kW	1.363	1736
1737					All On-Peak kWh	0.08531	/kWh	All On-Peak kWh	0.11287	/kWh	0.02756	1737
1738					All Off-Peak kWh	0.04598	/kWh	All Off-Peak kWh	0.06070	/kWh	0.01472	1738
1739			Minimum	Sum & Win								1739
1740					Minimum Basic Service Charge	$ 1.932	/day	Minimum Basic Service Charge	$ 2.418	/day	$ 0.486	1740
1741					Minimum Demand Charge	6.414	/kW	Minimum Demand Charge	7.572	/kW	1.158	1741
1742												1742
1743	E-221 AG	Water Pumping Service	Rate	Sum & Win	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	1743
1744					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	1744
1745					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	1745
1746					All kW	4.302	/kW	All kW	4.769	/kW	0.467	1746
1747					First 240 kWh	0.09060	/kWh	First 240 kWh	0.11988	/kWh	0.029	1747
1748					All additional kWh	0.06620	/kWh	All additional kWh	0.08751	/kWh	0.021	1748
1749			Minimum	Sum & Win								1749
1750					Minimum Basic Service Charge	$ 1.932	/day	Minimum Basic Service Charge	$ 2.418	/day	$ 0.486	1750
1751					Minimum Demand Charge	4.302	/kW	Minimum Demand Charge	4.769	/kW	0.467	1751
1752												1752
1753	E-221 AG TOU	Water Pumping Service	Rate	Sum	BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	1753
1754					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	1754
1755					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	1755
1756					On-Peak kW	4.489	/kW	On-Peak kW	5.018	/kW	0.529	1756
1757					On-Peak kWh	0.09674	/kWh	On-Peak kWh	0.12804	/kWh	0.031	1757
1758					Off-Peak kWh	0.06646	/kWh	Off-Peak kWh	0.08786	/kWh	0.021	1758
1759				Win								1759
1760					BSC: Self-Contained Meters	$ 1.110	/day	BSC: Self-Contained Meters	$ 1.389	/day	$ 0.279	1760
1761					BSC: Instrument-rated Meters	1.932	/day	BSC: Instrument-rated Meters	2.418	/day	0.486	1761
1762					BSC: Primary Meters	4.733	/day	BSC: Primary Meters	5.925	/day	1.192	1762
1763					On-Peak kW	4.489	/kW	On-Peak kW	5.018	/kW	0.529	1763
1764					On-Peak kWh	0.09674	/kWh	On-Peak kWh	0.12804	/kWh	0.031	1764
1765					Off-Peak kWh	0.06646	/kWh	Off-Peak kWh	0.08786	/kWh	0.021	1765
1766					Super Off-Peak kWh	0.03067	/kWh	Super Off-Peak kWh	0.04038	/kWh	0.010	1766
1767												1767
1768			Minimum	Sum & Win	Minimum Basic Service Charge	$ 1.932	/day	Minimum Basic Service Charge	$ 2.418	/day	$ 0.486	1768
1769					Minimum Demand Charge	4.489	/kW	Minimum Demand Charge	5.018	/kW	0.529	1769
1770												1770
1771	GS-SCHOOLS M	Time of Use for	Rate	Summer	BSC: Self-Contained Meters	$ 1.115	/day	BSC: Self-Contained Meters	$ 1.393	/day	$ 0.278	1771
1772		Elementary		Peak	BSC: Instrument-rated Meters	1.941	/kW	BSC: Instrument-rated Meters	2.424	/kW	0.483	1772
1773		and High Schools			BSC: Primary Meters	4.753	/kW	BSC: Primary Meters	5.937	/kW	1.184	1773
1774		0-400 kW			BSC: Transmission Meters	35.352	/kW	BSC: Transmission Meters	44.158	/kW	8.806	1774
1775					First 100 kW: Secondary	11.465	/kW	First 100 kW: Secondary	13.606	/kW	2.141	1775
1776					All remaining kW: Secondary	6.648	/kW	All remaining kW: Secondary	7.589	/kW	0.941	1776
1777					First 100 kW: Primary	10.723	/kW	First 100 kW: Primary	12.679	/kW	1.956	1777
1778					All remaining kW: Primary	5.904	/kW	All remaining kW: Primary	6.660	/kW	0.756	1778
1779					First 100 kW: Transmission	8.618	/kW	First 100 kW: Transmission	10.050	/kW	1.432	1779
1780					All remaining kW: Transmission	3.801	/kW	All remaining kW: Transmission	4.033	/kW	0.232	1780
1781					All On-Peak kWh:	0.17892	/kWh	All On-Peak kWh:	0.22343	/kWh	0.04451	1781
1782					All Off-Peak kWh:	0.06698	/kWh	All Off-Peak kWh:	0.08360	/kWh	0.01662	1782
1783												1783

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1784	GS-SCHOOLS M	Time of Use for	Rate	Winter	BSC: Self-Contained Meters	$ 1.115	/day	BSC: Self-Contained Meters	$ 1.393	/day	$ 0.278	1784
1785	(continued)	Elementary			BSC: Instrument-rated Meters	1.941	/kW	BSC: Instrument-rated Meters	2.424	/kW	0.483	1785
1786		and High Schools			BSC: Primary Meters	4.753	/kW	BSC: Primary Meters	5.937	/kW	1.184	1786
1787		0-400 kW			BSC: Transmission Meters	35.352	/kW	BSC: Transmission Meters	44.158	/kW	8.806	1787
1788					First 100 kW: Secondary	11.465	/kW	First 100 kW: Secondary	13.606	/kW	2.141	1788
1789					All remaining kW: Secondary	6.648	/kW	All remaining kW: Secondary	7.589	/kW	0.941	1789
1790					First 100 kW: Primary	10.723	/kW	First 100 kW: Primary	12.679	/kW	1.956	1790
1791					All remaining kW: Primary	5.904	/kW	All remaining kW: Primary	6.660	/kW	0.756	1791
1792					First 100 kW: Transmission	8.618	/kW	First 100 kW: Transmission	10.050	/kW	1.432	1792
1793					All remaining kW: Transmission	3.801	/kW	All remaining kW: Transmission	4.033	/kW	0.232	1793
1794					All On-Peak kWh:	0.11978	/kWh	All On-Peak kWh:	0.14956	/kWh	0.02978	1794
1795					All Off-Peak kWh:	0.04486	/kWh	All Off-Peak kWh:	0.05597	/kWh	0.01111	1795
1796												1796
1797	GS-SCHOOLS L	Time of Use for	Rate	Summer	BSC: Self-Contained Meters	$ 2.938	/day	BSC: Self-Contained Meters	$ 3.698	/day	$ 0.760	1797
1798		Elementary		Peak	BSC: Instrument-rated Meters	3.764	/kW	BSC: Instrument-rated Meters	4.738	/kW	0.974	1798
1799		and High Schools			BSC: Primary Meters	6.574	/kW	BSC: Primary Meters	8.275	/kW	1.701	1799
1800		401 kW and above			BSC: Transmission Meters	37.150	/kW	BSC: Transmission Meters	46.760	/kW	9.610	1800
1801					First 100 kW: Secondary	11.217	/kW	First 100 kW: Secondary	13.376	/kW	2.159	1801
1802					All remaining kW: Secondary	6.510	/kW	All remaining kW: Secondary	7.452	/kW	0.942	1802
1803					First 100 kW: Primary	10.487	/kW	First 100 kW: Primary	12.457	/kW	1.970	1803
1804					All remaining kW: Primary	5.784	/kW	All remaining kW: Primary	6.538	/kW	0.754	1804
1805					First 100 kW: Transmission	8.434	/kW	First 100 kW: Transmission	9.873	/kW	1.439	1805
1806					All remaining kW: Transmission	3.725	/kW	All remaining kW: Transmission	3.946	/kW	0.221	1806
1807					All On-Peak kWh:	0.16086	/kWh	All On-Peak kWh:	0.20238	/kWh	0.04152	1807
1808					All Off-Peak kWh:	0.06587	/kWh	All Off-Peak kWh:	0.08281	/kWh	0.01694	1808
1809												1809
1810				Winter	BSC: Self-Contained Meters	$ 2.938	/day	BSC: Self-Contained Meters	$ 3.698	/day	$ 0.760	1810
1811					BSC: Instrument-rated Meters	3.764	/kW	BSC: Instrument-rated Meters	4.738	/kW	0.974	1811
1812					BSC: Primary Meters	6.574	/kW	BSC: Primary Meters	8.275	/kW	1.701	1812
1813					BSC: Transmission Meters	37.150	/kW	BSC: Transmission Meters	46.760	/kW	9.610	1813
1814					First 100 kW: Secondary	11.217	/kW	First 100 kW: Secondary	13.376	/kW	2.159	1814
1815					All remaining kW: Secondary	6.510	/kW	All remaining kW: Secondary	7.452	/kW	0.942	1815
1816					First 100 kW: Primary	10.487	/kW	First 100 kW: Primary	12.457	/kW	1.970	1816
1817					All remaining kW: Primary	5.784	/kW	All remaining kW: Primary	6.538	/kW	0.754	1817
1818					First 100 kW: Transmission	8.434	/kW	First 100 kW: Transmission	9.873	/kW	1.439	1818
1819					All remaining kW: Transmission	3.725	/kW	All remaining kW: Transmission	3.946	/kW	0.221	1819
1820					All On-Peak kWh:	0.10767	/kWh	All On-Peak kWh:	0.13543	/kWh	0.02776	1820
1821					All Off-Peak kWh:	0.04409	/kWh	All Off-Peak kWh:	0.05540	/kWh	0.01131	1821
1822												1822
1823	CPP-GS	General Service	Rate	Summer	Critical Peak Price	$ 0.25000	/kWh	Critical Peak Price	$ 0.25000	/kWh	$ -	1823
1824		Critical Peak Pricing										1824
1825					Energy Discount E-32 M	$ (0.010351)	/kWh	Energy Discount E-32 M	$ (0.010351)	/kWh	$ -	1825
1826					Energy Discount E-32 L	(0.009533)	/kWh	Energy Discount E-32 L	(0.009533)	/kWh	-	1826
1827					Energy Discount E-32 TOU M	(0.009266)	/kWh	Energy Discount E-32 TOU M	(0.009266)	/kWh	-	1827
1828					Energy Discount E-32 TOU L	(0.008680)	/kWh	Energy Discount E-32 TOU L	(0.008680)	/kWh	-	1828
1829					Energy Discount E-34	(0.008519)	/kWh	Energy Discount E-34	(0.008519)	/kWh	-	1829
1830					Energy Discount E-35	(0.007396)	/kWh	Energy Discount E-35	(0.007396)	/kWh	-	1830
1831					Energy Discount E-221	(0.006116)	/kWh	Energy Discount E-221	(0.006116)	/kWh	-	1831
1832												1832
1833												1833
1834	E-56R	Standard Contract -	Rate	Sum & Win	All kWh	Varies by Customer		All kWh	Varies by Customer		$ -	1834
1835		Solar			All kW	Varies by Customer		All kW	Varies by Customer		-	1835
1836												1836
1837												1837

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1838	EPR-2	Purchase Rates for	Rate	Summer	Non-Firm On-Peak	$ 0.02989	/kWh	Non-Firm On-Peak	$ 0.02989	/kWh	$ -	1838
1839		Qualified Facilities			Non-Firm Off-Peak	0.02897	/kWh	Non-Firm Off-Peak	0.02897	/kWh	-	1839
1840		of 100 kW or less			Firm On-Peak	0.04297	/kWh	Firm On-Peak	0.04297	/kWh	-	1840
1841					Firm Off-Peak	0.03009	/kWh	Firm Off-Peak	0.03009	/kWh	-	1841
1842												1842
1843				Winter	Non-Firm On-Peak	$ 0.03040	/kWh	Non-Firm On-Peak	$ 0.03040	/kWh	$ -	1843
1844					Non-Firm Off-Peak	0.02831	/kWh	Non-Firm Off-Peak	0.02831	/kWh	-	1844
1845					Firm On-Peak	0.03040	/kWh	Firm On-Peak	0.03040	/kWh	-	1845
1846					Firm Off-Peak	0.02831	/kWh	Firm Off-Peak	0.02831	/kWh	-	1846
1847												1847
1848												1848
1849	EPR-6	GS and Legacy	Rate	Sum & Win	Energy Credit for Excess Generation	$ 0.02895	/kWh	Energy Credit for Excess Generation	$ 0.02895	/kWh	$ -	1849
1850		Residential Net Metering Rate										1850
1851												1851
1852	IRR	Extra Large	Rate	1 Year	Option 1 - 30 Minute Notice	$ 7.975	/kW-Yr	Option 1 - 30 Minute Notice	$ 7.975	/kW-Yr	$ -	1852
1853		General Service			Option 1 - 30 Minute Notice	0.09969	/kWh	Option 1 - 30 Minute Notice	0.09969	/kWh	-	1853
1854		Interruptible Rate Rider			Option 1 - 2-Hour Notice	7.178	/kW-Yr	Option 1 - 2-Hour Notice	7.178	/kW-Yr	-	1854
1855					Option 1 - 2-Hour Notice	0.08972	/kWh	Option 1 - 2-Hour Notice	0.08972	/kWh	-	1855
1856					Option 2 - 30 Minute Notice	5.995	/kW-Yr	Option 2 - 30 Minute Notice	5.995	/kW-Yr	-	1856
1857					Option 2 - 30 Minute Notice	0.07493	/kWh	Option 2 - 30 Minute Notice	0.07493	/kWh	-	1857
1858					Option 2 - 2-Hour Notice	5.395	/kW-Yr	Option 2 - 2-Hour Notice	5.395	/kW-Yr	-	1858
1859					Option 2 - 2-Hour Notice	0.06745	/kWh	Option 2 - 2-Hour Notice	0.06745	/kWh	-	1859
1860												1860
1861		Extra Large		5 Year	Option 1 - 30 Minute Notice	$ 9.882	/kW-Yr	Option 1 - 30 Minute Notice	$ 9.882	/kW-Yr	$ -	1861
1862		General Service			Option 1 - 30 Minute Notice	0.12353	/kWh	Option 1 - 30 Minute Notice	0.12353	/kWh	-	1862
1863		Interruptible Rate Rider			Option 1 - 2-Hour Notice	8.894	/kW-Yr	Option 1 - 2-Hour Notice	8.894	/kW-Yr	-	1863
1864					Option 1 - 2-Hour Notice	0.11117	/kWh	Option 1 - 2-Hour Notice	0.11117	/kWh	-	1864
1865					Option 2 - 30 Minute Notice	7.428	/kW-Yr	Option 2 - 30 Minute Notice	7.428	/kW-Yr	-	1865
1866					Option 2 - 30 Minute Notice	0.09285	/kWh	Option 2 - 30 Minute Notice	0.09285	/kWh	-	1866
1867					Option 2 - 2-Hour Notice	6.685	/kW-Yr	Option 2 - 2-Hour Notice	6.685	/kW-Yr	-	1867
1868					Option 2 - 2-Hour Notice	0.08356	/kWh	Option 2 - 2-Hour Notice	0.08356	/kWh	-	1868
1869												1869
1870	PPR	Preference Power Rider	Rate	Summer	All preference power kWh with allotments 1 MW and above	$ 0.04729	/kWh	All preference power kWh with allotments 1 MW and above	$ 0.06034	/kWh	$ 0.01305	1870
1871					All preference power kWh with allotments 401 kW to 1 MW	0.05731	/kWh	All preference power kWh with allotments 401 kW to 1 MW	0.07232	/kWh	0.01501	1871
1872					All preference power kWh with allotments 0 kW to 400kW	0.06185	/kWh	All preference power kWh with allotments 0 kW to 400kW	0.07750	/kWh	0.01565	1872
1873												1873
1874				Winter	All preference power kWh with allotments 1 MW and above	$ 0.04729	/kWh	All preference power kWh with allotments 1 MW and above	$ 0.06034	/kWh	$ 0.01305	1874
1875					All preference power kWh with allotments 401 kW to 1 MW	0.04287	/kWh	All preference power kWh with allotments 401 kW to 1 MW	0.05428	/kWh	0.01141	1875
1876					All preference power kWh with allotments 0 kW to 400kW	0.04846	/kWh	All preference power kWh with allotments 0 kW to 400kW	0.06032	/kWh	0.01186	1876
1877												1877
1878	SD-1	School Discount Rider	Rate	Sum & Win	All kWh	$ (0.00234)	/kWh	All kWh	$ (0.00293)	/kWh	$ (0.00059)	1878
1879												1879
1880	SGSP	Schools	Rate	Sum & Win	Solar Charge E-32 M & E-32 L	$ 0.07665	/kWh	Solar Charge E-32 M & E-32 L	$ 0.07665	/kWh	$ -	1880
1881		and Government			Solar Charge E-32 L	0.04660	/kWh	Solar Charge E-32 L	0.04660	/kWh	-	1881
1882		Solar Program Rider			Solar Charge E-32 TOU S, E-32 TOU M, E-32 TC	0.05502	/kWh	Solar Charge E-32 TOU S, E-32 TOU M, E-32 TC	0.05502	/kWh	-	1882
1883					Solar Charge GS-Schools M and GS-Schools L	0.07571	/kWh	Solar Charge GS-Schools M and GS-Schools L	0.07571	/kWh	-	1883
1884					Solar Charge E-34	0.04236	/kWh	Solar Charge E-34	0.04236	/kWh	-	1884
1885					Solar Charge E-35	0.04128	/kWh	Solar Charge E-35	0.04128	/kWh	-	1885

Supporting Schedules:
N/A

Recap Schedules:
N/A

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ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	Line No.
1886												1886
1887	RCP	Resource Comparison	Rate	Sum & Win	Tranche 2017 - All Exported kWh	$ 0.12900	/kWh	Tranche 2017 - All Exported kWh	$ 0.12900	/kWh	$ -	1887
1888		Proxy Export Rate			Tranche 2018 - All Exported kWh	0.11610	/kWh	Tranche 2018 - All Exported kWh	0.11610	/kWh	-	1888
1889					Tranche 2019 & 2020 - All Exported kWh	0.10450	/kWh	Tranche 2019 & 2020 - All Exported kWh	0.10450	/kWh	-	1889
1890					Tranche 2021 - All Exported kWh	0.09405	/kWh	Tranche 2021 - All Exported kWh	0.09405	/kWh	-	1890
1891					Tranche 2022 - All Exported kWh	0.08465	/kWh	Tranche 2022 - All Exported kWh	0.08465	/kWh		1891
1892												1892
1893	AG-X	Alternative Generation	Rate	Sum & Win	Billed on Rate Schedule E-32 M, E-32 L, E-32TOU M, E-32TOUL, E-34 or Rate Schedule E-35			Billed on Rate Schedule E-32 M, E-32 L, E-32TOU M, E-32TOUL, E-34 or Rate Schedule E-35				1893
1894		Extra Large Service			Generation will be scheduled at market price plus uplift.			Generation will be scheduled at market price plus uplift.				1894
1895					Administrative Management Fee	$0.00171	/kWh	Administrative Management Fee	$0.00164	/kWh	$ (0.00007)	1895
1896					Reserve Capacity Charge	5.2480	/kW	Reserve Capacity Charge	6.4530	/kW	1.2050	1896
1897												1897
1898	DSMAC-1[1]	Demand Side	Adjustment	Sum & Win	all kWh	$ 0.001374	/kWh	TO BE DETERMINED			$ -	1898
1899		Management			all kW	0.508	/kW				-	1899
1900		Adjustment Charge										1900
1901												1901
1902	RCDAC-1[1]	Returning Customer	Adjustment	Sum & Win	Customers over 3MW	Varies by Customer		NO CHANGE				1902
1903		Direct Access Charge										1903
1904												1904
1905	PSA-1[1]	Power Supply	Adjustment	Sum & Win	PSA Historical	$ 0.012386	/kWh	TO BE DETERMINED			$ -	1905
1906		Adjustment			PSA Forward	(0.004842)	/kWh				-	1906
1907					PSA Transition	-	/kWh				-	1907
1908												1908

Supporting Schedules:
N/A

Recap Schedules:
N/A

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ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	Line No.
1909	REAC-1[1]	Renewable Energy	Adjustment	Sum & Win	All kWh	$ 0.007812	/kWh				$ -	1909
1910		Standard			Cap for all Residential Services	3.00	/service month				-	1910
1911					Cap for General Services 100 kW or less	50.00	/service month				-	1911
1912					Cap for General Services over 100, under 400	200.00	/service month				-	1912
1913					Cap for General Services over 400, under 300(	500.00	/service month				-	1913
1914					Cap for General Services over 3000 kW	2,500.00	/service month				-	1914
1915												1915
1916		Alternative REAC Charges		Sum & Win	Flat Charge for Residential Services	$ 2.62	/service month				$ -	1916
1917		for customers			Minimum for General Services 20 kW or less	6.52	/service month				-	1917
1918		with on-site renewable			Cap for General Services 20 kW or less	50.00	/service month				-	1918
1919						32.62	/service month				-	1919
		distribution systems			Minimum for GS over 20 kW, under 101 kW							
1920					Cap for GS over 20 kW, under 101 kW	50.00	/service month				-	1920
1921						174.75	/service month				-	1921
					Flat Charge for GS over 100, under 400 kW							
1922					Flat Charge for GS over 400, under 3000 kW	456.58	/service month				-	1922
1923					Flat Charge for GS over 3000 kW	2,500.00	/service month				-	1923
1924												1924
1925	EIS[1]	Environmental	Adjustment	Sum & Win	All kWh	$ 0.000403	/kWh				$ -	1925
1926												1926
1927	TCA-1[1]	Transmission	Adjustment	Sum & Win	Residential - kWh	$ 0.000807	/kWh				$ -	1927
1928					General service 20 kW or less	(0.000542)	/kWh				-	1928
1929					General service over 20 kW, under 3,000 kW	(0.295)	/kW				-	1929
1930					XL General service 3,000 kW and over	(0.690)	/kW				-	1930
1931												1931
1932	LFCR[1]	Lost Fixed Cost	Adjustment	Sum & Win	Customer on a demand rate	$ 0.775	/kW				$ -	1932
1933		Recovery			Customers on an energy-only rate	0.00263	/kWh				-	1933
1934												1934
1935	LFCR-DG[1]	Legacy Adjustment for	Adjustment	Sum & Win	Generators registered with APS	$ 0.70	/kW-DC				$ -	1935
1936		Distributed Generation			Generators not registered APS	3.00	/kW-DC				-	1936
1937												1937
1938	GPS-1[1]	Green Power	Adjustment	Sum & Win	100 kWh Block	$ 1.02	/kWh Block				$ -	1938
1939		Block Schedule										1939
1940												1940
1941	GPS-2[1]	Green Power	Adjustment	Sum & Win	100.0% total monthly kWh	$ 0.01020	/kWh				$ -	1941
1942		Percent Schedule			50.0% total monthly kWh	0.00510	/kWh				-	1942
1943					35.0% total monthly kWh	0.00360	/kWh				-	1943
1944					10.0% total monthly kWh	0.00100	/kWh				-	1944
1945												1945

TO BE DETERMINED

CANCEL

TO BE DETERMINED

CANCEL

NO CHANGE

NO CHANGE

NO CHANGE

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-3
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Test Year Ended June 30, 2022

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	€ Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	Line No.
1946	GPS-3[1]	Green Power	Adjustment	Sum & Win	100 kWh Block	$ 1.02	/kWh Block	NO CHANGE			$ -	1946
1947		Block Schedule			Minimum purchase	500.00	/Transaction				-	1947
1948		for Special Events										1948
1949												1949
1950	SDR	Self-Directed	Adjustment	Sum & Win	Varies per customer			NO CHANGE				1950
1951		Renewable Resources										1951
1952												1952
1953	TEAM[1]	Tax Expense	Adjustment	Sum & Win	All kWh	$ -	/kWh	All kWh	$ -	/kWh	$ -	1953
1954		Adjustor Mechanism										1954
1955		(combined)										1955

Footnote:
1) These adjustment schedules may be modified outside of a rate case in accordance with the adjustment mechanism's Plan of Administration. These schedules do not impact revenue calculations.
NOTES TO SCHEDULE
1) Present rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Base Rates effective 12/1/2021; Adjustor Rates effective 10/1/2022.

Supporting Schedules:
N/A

Recap Schedules:
N/A

Notes: There may be variations in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-1 Small

Summer	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	20.78	25.64	4.86	23.4%
101-200	32.08	39.48	7.40	23.1%
201-300	43.37	53.33	9.96	23.0%
301-400	54.67	67.18	12.51	22.9%
401-500	65.97	81.03	15.06	22.8%
501-600	77.27	94.87	17.60	22.8%

Winter	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	20.78	25.64	4.86	23.4%
101-200	32.08	39.48	7.40	23.1%
201-300	43.37	53.33	9.96	23.0%
301-400	54.67	67.18	12.51	22.9%
401-500	65.97	81.03	15.06	22.8%
501-600	77.27	94.87	17.60	22.8%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-1 Medium

Summer	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	97.97	120.37	22.40	22.9%
701-800	110.26	135.42	25.16	22.8%
801-900	122.54	150.48	27.94	22.8%
901-1000	134.82	165.53	30.71	22.8%

Winter	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	97.97	120.37	22.40	22.9%
701-800	110.26	135.42	25.16	22.8%
801-900	122.54	150.48	27.94	22.8%
901-1000	134.82	165.53	30.71	22.8%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-1 Large

Summer	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
1001-1100	160.26	196.86	36.60	22.8%
1101-1200	173.74	213.40	39.66	22.8%
1201-1300	187.21	229.93	42.72	22.8%
1301-1400	200.69	246.46	45.77	22.8%
1401-1500	214.17	263.00	48.83	22.8%
1501-1600	227.65	279.53	51.88	22.8%
1601-1700	241.13	296.06	54.93	22.8%
1701-1800	254.60	312.59	57.99	22.8%
1801-1900	268.08	329.13	61.05	22.8%
1901-2000	281.56	345.66	64.10	22.8%

Winter	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
1001-1100	160.26	196.86	36.60	22.8%
1101-1200	173.74	213.40	39.66	22.8%
1201-1300	187.21	229.93	42.72	22.8%
1301-1400	200.69	246.46	45.77	22.8%
1401-1500	214.17	263.00	48.83	22.8%
1501-1600	227.65	279.53	51.88	22.8%
1601-1700	241.13	296.06	54.93	22.8%
1701-1800	254.60	312.59	57.99	22.8%
1801-1900	268.08	329.13	61.05	22.8%
1901-2000	281.56	345.66	64.10	22.8%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-TOU-E

Summer	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	103.66	127.58	23.92	23.1%
701-800	116.74	143.64	26.90	23.0%
801-900	129.80	159.69	29.89	23.0%
901-1000	142.87	175.74	32.87	23.0%
1001-1100	155.94	191.78	35.84	23.0%
1101-1200	169.00	207.84	38.84	23.0%
1201-1300	182.07	223.89	41.82	23.0%
1301-1400	195.14	239.94	44.80	23.0%
1401-1500	208.21	255.98	47.77	22.9%
1501-1600	221.28	272.03	50.75	22.9%
1601-1700	234.35	288.09	53.74	22.9%
1701-1800	247.41	304.14	56.73	22.9%
1801-1900	260.48	320.19	59.71	22.9%
1901-2000	273.74	336.47	62.73	22.9%
2001-2100	286.80	352.52	65.72	22.9%
2101-2200	299.87	368.58	68.71	22.9%
2201-2300	312.94	384.62	71.68	22.9%
2301-2400	326.01	400.67	74.66	22.9%
2401-2500	339.08	416.72	77.64	22.9%
2501-2600	352.15	432.78	80.63	22.9%
2601-2700	365.21	448.83	83.62	22.9%
2701-2800	378.29	464.87	86.58	22.9%
2801-2900	391.35	480.92	89.57	22.9%
2901-3000	404.41	496.97	92.56	22.9%
3001-3100	417.49	513.03	95.54	22.9%
3101-3200	430.55	529.07	98.52	22.9%
3201-3300	443.81	545.36	101.55	22.9%
3301-3400	456.88	561.41	104.53	22.9%
3401-3500	469.95	577.47	107.52	22.9%
3501-3600	483.01	593.51	110.50	22.9%
3601-3700	496.09	609.56	113.47	22.9%
3701-3800	509.15	625.61	116.46	22.9%
3801-3900	522.21	641.66	119.45	22.9%
3901-4000	535.29	657.71	122.42	22.9%
4001-5000	666.15	818.45	152.30	22.9%

R-TOU-E Summer Average Energy On-Peak %: 12.1%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-TOU-E

Winter	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under	Monthly Bill under	Change	
kWh block	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	92.28	113.35	21.07	22.8%
701-800	103.82	127.50	23.68	22.8%
801-900	115.26	141.51	26.25	22.8%
901-1000	126.69	155.53	28.84	22.8%
1001-1100	138.24	169.67	31.43	22.7%
1101-1200	149.69	183.69	34.00	22.7%
1201-1300	161.12	197.70	36.58	22.7%
1301-1400	172.66	211.84	39.18	22.7%
1401-1500	184.10	225.86	41.76	22.7%
1501-1600	195.55	239.88	44.33	22.7%
1601-1700	207.07	254.01	46.94	22.7%
1701-1800	218.52	268.03	49.51	22.7%
1801-1900	229.96	282.04	52.08	22.6%
1901-2000	241.50	296.19	54.69	22.6%
2001-2100	252.94	310.20	57.26	22.6%
2101-2200	264.55	324.43	59.88	22.6%
2201-2300	275.92	338.36	62.44	22.6%
2301-2400	287.35	352.37	65.02	22.6%
2401-2500	298.97	366.60	67.63	22.6%
2501-2600	310.33	380.52	70.19	22.6%
2601-2700	321.78	394.54	72.76	22.6%
2701-2800	333.38	408.77	75.39	22.6%
2801-2900	344.75	422.70	77.95	22.6%
2901-3000	356.20	436.71	80.51	22.6%
3001-3100	367.81	450.95	83.14	22.6%
3101-3200	379.25	464.96	85.71	22.6%
3201-3300	390.62	478.89	88.27	22.6%
3301-3400	402.24	493.12	90.88	22.6%
3401-3500	413.67	507.14	93.47	22.6%
3501-3600	425.04	521.05	96.01	22.6%
3601-3700	436.65	535.29	98.64	22.6%
3701-3800	448.10	549.30	101.20	22.6%
3801-3900	459.45	563.23	103.78	22.6%
3901-4000	471.07	577.46	106.39	22.6%
4001-5000	585.76	717.99	132.23	22.6%

R-TOU-E Winter Average Energy On-Peak %:	9.3%
R-TOU-E Winter Average Energy Super Off-Peak %:	12.3%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-2

Summer		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	1.6	85.04	104.80	19.76	23.2%
701-800	2.3	99.25	122.30	23.05	23.2%
801-900	3.2	115.13	141.87	26.74	23.2%
901-1000	3.8	128.59	158.43	29.84	23.2%
1001-1100	4.4	141.98	174.92	32.94	23.2%
1101-1200	4.9	154.62	190.46	35.84	23.2%
1201-1300	5.4	167.27	206.00	38.73	23.2%
1301-1400	5.8	179.06	220.46	41.40	23.1%
1401-1500	6.2	190.89	234.99	44.10	23.1%
1501-1600	6.6	202.72	249.52	46.80	23.1%
1601-1700	7.0	214.51	263.98	49.47	23.1%
1701-1800	7.3	225.53	277.51	51.98	23.0%
1801-1900	7.7	237.32	291.96	54.64	23.0%
1901-2000	8.1	249.16	306.50	57.34	23.0%
2001-2100	8.4	260.19	320.00	59.81	23.0%
2101-2200	8.7	271.16	333.46	62.30	23.0%
2201-2300	9.1	282.99	348.00	65.01	23.0%
2301-2400	9.4	294.03	361.51	67.48	23.0%
2401-2500	9.8	305.80	375.98	70.18	22.9%
2501-2600	10.1	316.83	389.49	72.66	22.9%
2601-2700	10.5	328.66	404.02	75.36	22.9%
2701-2800	10.7	338.84	416.46	77.62	22.9%
2801-2900	11.1	350.67	430.99	80.32	22.9%
2901-3000	11.3	360.89	443.50	82.61	22.9%
3001-3100	11.6	371.86	456.95	85.09	22.9%
3101-3200	12.0	383.70	471.47	87.77	22.9%
3201-3300	12.3	394.72	484.99	90.27	22.9%
3301-3400	12.6	405.71	498.44	92.73	22.9%
3401-3500	12.7	415.12	509.94	94.82	22.8%
3501-3600	13.2	427.76	525.48	97.72	22.8%
3601-3700	13.4	437.92	537.92	100.00	22.8%
3701-3800	13.7	448.95	551.43	102.48	22.8%
3801-3900	13.9	459.17	563.94	104.77	22.8%
3901-4000	14.4	471.76	579.42	107.66	22.8%
4001-5000	15.5	566.52	695.17	128.65	22.7%

R-2 Summer Average Energy On-Peak %: 19.7%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-2

Winter		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	1.8	83.15	102.07	18.92	22.8%
701-800	2.2	94.40	115.87	21.47	22.7%
801-900	2.2	102.46	125.68	23.22	22.7%
901-1000	2.5	112.91	138.47	25.56	22.6%
1001-1100	2.8	123.41	151.30	27.89	22.6%
1101-1200	3.2	134.67	165.12	30.45	22.6%
1201-1300	3.5	145.14	177.95	32.81	22.6%
1301-1400	3.8	155.61	190.75	35.14	22.6%
1401-1500	4.0	165.28	202.57	37.29	22.6%
1501-1600	4.3	175.73	215.37	39.64	22.6%
1601-1700	4.6	186.22	228.20	41.98	22.5%
1701-1800	4.9	196.67	241.01	44.34	22.5%
1801-1900	5.1	206.34	252.82	46.48	22.5%
1901-2000	5.4	216.80	265.63	48.83	22.5%
2001-2100	5.6	226.47	277.45	50.98	22.5%
2101-2200	5.9	236.93	290.24	53.31	22.5%
2201-2300	6.1	246.60	302.08	55.48	22.5%
2301-2400	6.3	256.25	313.86	57.61	22.5%
2401-2500	6.6	266.72	326.70	59.98	22.5%
2501-2600	6.8	276.38	338.48	62.10	22.5%
2601-2700	7.0	286.06	350.31	64.25	22.5%
2701-2800	7.2	295.69	362.09	66.40	22.5%
2801-2900	7.5	306.19	374.93	68.74	22.5%
2901-3000	7.6	315.02	385.70	70.68	22.4%
3001-3100	7.8	324.70	397.52	72.82	22.4%
3101-3200	8.0	334.33	409.32	74.99	22.4%
3201-3300	8.2	344.02	421.14	77.12	22.4%
3301-3400	8.5	354.46	433.94	79.48	22.4%
3401-3500	8.6	363.34	444.75	81.41	22.4%
3501-3600	9.0	374.61	458.55	83.94	22.4%
3601-3700	9.2	384.27	470.38	86.11	22.4%
3701-3800	9.6	395.54	484.19	88.65	22.4%
3801-3900	9.7	404.40	495.00	90.60	22.4%
3901-4000	9.9	414.05	506.79	92.74	22.4%
4001-5000	10.9	502.57	614.72	112.15	22.3%

R-2 Winter Average Energy On-Peak %: 15.5%
R-2 Winter Average Energy Super Off-Peak %: 0.0%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-3

Summer		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	2.8	101.75	125.32	23.57	23.2%
701-800	3.1	112.87	138.95	26.08	23.1%
801-900	3.4	124.00	152.58	28.58	23.0%
901-1000	3.6	133.43	164.12	30.69	23.0%
1001-1100	3.9	144.56	177.75	33.19	23.0%
1101-1200	4.2	155.68	191.37	35.69	22.9%
1201-1300	4.4	165.12	202.91	37.79	22.9%
1301-1400	4.7	176.24	216.54	40.30	22.9%
1401-1500	5.0	187.37	230.19	42.82	22.9%
1501-1600	5.2	196.80	241.70	44.90	22.8%
1601-1700	5.5	207.92	255.33	47.41	22.8%
1701-1800	5.7	217.36	266.86	49.50	22.8%
1801-1900	6.0	228.55	280.59	52.04	22.8%
1901-2000	6.2	238.00	292.11	54.11	22.7%
2001-2100	6.5	249.11	305.74	56.63	22.7%
2101-2200	6.7	258.55	317.27	58.72	22.7%
2201-2300	6.9	267.99	328.79	60.80	22.7%
2301-2400	7.2	279.11	342.43	63.32	22.7%
2401-2500	7.5	290.24	356.06	65.82	22.7%
2501-2600	7.6	297.98	365.48	67.50	22.7%
2601-2700	8.0	310.80	381.22	70.42	22.7%
2701-2800	8.3	321.91	394.86	72.95	22.7%
2801-2900	8.5	331.36	406.38	75.02	22.6%
2901-3000	8.7	340.78	417.90	77.12	22.6%
3001-3100	9.0	351.92	431.54	79.62	22.6%
3101-3200	9.3	363.11	445.27	82.16	22.6%
3201-3300	9.6	374.24	458.90	84.66	22.6%
3301-3400	9.8	383.67	470.42	86.75	22.6%
3401-3500	10.1	394.80	484.06	89.26	22.6%
3501-3600	10.3	404.22	495.58	91.36	22.6%
3601-3700	10.5	413.67	507.12	93.45	22.6%
3701-3800	10.7	423.10	518.63	95.53	22.6%
3801-3900	11.1	435.91	534.37	98.46	22.6%
3901-4000	11.3	445.35	545.91	100.56	22.6%
4001-5000	12.5	526.28	644.34	118.06	22.4%

R-3 Summer Average Energy On-Peak %: 11.1%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
R-3

Winter		*(A)*	*(B)*	*(C)*	*(D)*
		Monthly Bill under	Monthly Bill under	Change	
kWh block	On-Pk kW	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	1.8	70.86	86.65	15.79	22.3%
701-800	2.2	80.95	99.01	18.06	22.3%
801-900	2.2	86.32	105.42	19.10	22.1%
901-1000	2.5	95.22	116.29	21.07	22.1%
1001-1100	2.8	104.14	127.17	23.03	22.1%
1101-1200	3.2	114.24	139.50	25.26	22.1%
1201-1300	3.5	123.17	150.41	27.24	22.1%
1301-1400	3.8	132.06	161.25	29.19	22.1%
1401-1500	4.0	139.81	170.66	30.85	22.1%
1501-1600	4.3	148.72	181.53	32.81	22.1%
1601-1700	4.6	157.61	192.35	34.74	22.0%
1701-1800	4.9	166.55	203.26	36.71	22.0%
1801-1900	5.1	174.27	212.63	38.36	22.0%
1901-2000	5.4	183.19	223.51	40.32	22.0%
2001-2100	5.6	190.92	232.88	41.96	22.0%
2101-2200	5.9	199.86	243.80	43.94	22.0%
2201-2300	6.1	207.56	253.14	45.58	22.0%
2301-2400	6.3	215.31	262.57	47.26	21.9%
2401-2500	6.6	224.23	273.43	49.20	21.9%
2501-2600	6.8	231.93	282.78	50.85	21.9%
2601-2700	7.0	239.69	292.19	52.50	21.9%
2701-2800	7.2	247.40	301.57	54.17	21.9%
2801-2900	7.5	256.33	312.46	56.13	21.9%
2901-3000	7.6	262.86	320.35	57.49	21.9%
3001-3100	7.8	270.62	329.77	59.15	21.9%
3101-3200	8.0	278.32	339.12	60.80	21.8%
3201-3300	8.2	286.05	348.49	62.44	21.8%
3301-3400	8.5	294.99	359.41	64.42	21.8%
3401-3500	8.6	301.50	367.27	65.77	21.8%
3501-3600	9.0	311.63	379.66	68.03	21.8%
3601-3700	9.2	319.34	389.03	69.69	21.8%
3701-3800	9.6	329.47	401.41	71.94	21.8%
3801-3900	9.7	335.99	409.28	73.29	21.8%
3901-4000	9.9	343.75	418.71	74.96	21.8%
4001-5000	10.9	409.20	497.77	88.57	21.6%

R-3 Winter Average Energy On-Peak %: 8.4%
R-3 Winter Average Energy Super Off-Peak %: 9.3%

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
Technology Time-of-Use with Demand
R-TECH

Summer

kWh block	On-Pk kW	Off-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	1.6	3.0	78.77	96.46	17.69	22.5%
701-800	2.3	4.0	97.17	119.17	22.00	22.6%
801-900	3.2	6.0	125.69	154.53	28.84	22.9%
901-1000	3.8	7.0	148.38	182.58	34.20	23.0%
1001-1100	4.4	8.0	171.06	210.65	39.59	23.1%
1101-1200	4.9	9.0	191.80	236.29	44.49	23.2%
1201-1300	5.4	10.0	212.54	261.92	49.38	23.2%
1301-1400	5.8	11.0	231.33	285.13	53.80	23.3%
1401-1500	6.2	11.0	243.89	300.55	56.66	23.2%
1501-1600	6.6	12.0	262.68	323.75	61.07	23.2%
1601-1700	7.0	13.0	281.48	346.97	65.49	23.3%
1701-1800	7.3	14.0	298.34	367.74	69.40	23.3%
1801-1900	7.7	14.0	310.91	383.16	72.25	23.2%
1901-2000	8.1	15.0	329.70	406.36	76.66	23.3%
2001-2100	8.4	16.0	346.56	427.15	80.59	23.3%
2101-2200	8.7	16.0	357.18	440.13	82.95	23.2%
2201-2300	9.1	17.0	375.97	463.33	87.36	23.2%
2301-2400	9.4	17.0	386.58	476.31	89.73	23.2%
2401-2500	9.8	18.0	405.38	499.52	94.14	23.2%
2501-2600	10.1	19.0	422.23	520.31	98.08	23.2%
2601-2700	10.5	19.0	434.80	535.73	100.93	23.2%
2701-2800	10.7	20.0	449.71	554.09	104.38	23.2%
2801-2900	11.1	21.0	468.50	577.27	108.77	23.2%
2901-3000	11.3	21.0	477.16	587.84	110.68	23.2%
3001-3100	11.6	21.0	487.78	600.82	113.04	23.2%
3101-3200	12.0	22.0	506.59	624.04	117.45	23.2%
3201-3300	12.3	23.0	523.43	644.81	121.38	23.2%
3301-3400	12.6	23.0	534.06	657.80	123.74	23.2%
3401-3500	12.7	23.0	540.78	665.93	125.15	23.1%
3501-3600	13.2	24.0	561.53	691.56	130.03	23.2%
3601-3700	13.4	25.0	576.44	709.91	133.47	23.2%
3701-3800	13.7	25.0	587.06	722.89	135.83	23.1%
3801-3900	13.9	26.0	601.96	741.25	139.29	23.1%
3901-4000	14.4	27.0	622.71	766.88	144.17	23.2%
4001-5000	15.5	29.0	704.42	866.16	161.74	23.0%

R-TECH Summer Average Energy On-Peak %: 13.8%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
Technology Time-of-Use with Demand
R-TECH

Winter

kWh block	On-Pk kW	Off-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	1.8	5.0	71.38	87.22	15.84	22.2%
701-800	2.2	6.0	87.75	107.39	19.64	22.4%
801-900	2.2	6.0	92.40	112.93	20.53	22.2%
901-1000	2.5	7.0	107.39	131.37	23.98	22.3%
1001-1100	2.8	7.0	116.14	142.04	25.90	22.3%
1101-1200	3.2	8.0	132.50	162.19	29.69	22.4%
1201-1300	3.5	9.0	147.50	180.66	33.16	22.5%
1301-1400	3.8	10.0	162.50	199.13	36.63	22.5%
1401-1500	4.0	10.0	169.88	208.07	38.19	22.5%
1501-1600	4.3	11.0	184.88	226.52	41.64	22.5%
1601-1700	4.6	12.0	199.87	244.98	45.11	22.6%
1701-1800	4.9	13.0	214.86	263.44	48.58	22.6%
1801-1900	5.1	13.0	222.26	272.39	50.13	22.6%
1901-2000	5.4	14.0	237.25	290.84	53.59	22.6%
2001-2100	5.6	15.0	250.88	307.60	56.72	22.6%
2101-2200	5.9	15.0	259.64	318.25	58.61	22.6%
2201-2300	6.1	16.0	273.26	335.00	61.74	22.6%
2301-2400	6.3	16.0	280.65	343.95	63.30	22.6%
2401-2500	6.6	17.0	295.65	362.40	66.75	22.6%
2501-2600	6.8	18.0	309.28	379.16	69.88	22.6%
2601-2700	7.0	18.0	316.66	388.10	71.44	22.6%
2701-2800	7.2	19.0	330.30	404.85	74.55	22.6%
2801-2900	7.5	20.0	345.29	423.32	78.03	22.6%
2901-3000	7.6	20.0	351.31	430.56	79.25	22.6%
3001-3100	7.8	20.0	358.69	439.51	80.82	22.5%
3101-3200	8.0	21.0	372.31	456.24	83.93	22.5%
3201-3300	8.2	21.0	379.70	465.20	85.50	22.5%
3301-3400	8.5	22.0	394.70	483.66	88.96	22.5%
3401-3500	8.6	22.0	400.71	490.90	90.19	22.5%
3501-3600	9.0	23.0	417.08	511.07	93.99	22.5%
3601-3700	9.2	24.0	430.71	527.81	97.10	22.5%
3701-3800	9.6	25.0	447.07	547.97	100.90	22.6%
3801-3900	9.7	25.0	453.10	555.22	102.12	22.5%
3901-4000	9.9	26.0	466.72	571.97	105.25	22.6%
4001-5000	10.9	28.0	539.41	659.98	120.57	22.4%

R-TECH Winter Average Energy On-Peak %: 8.8%
R-TECH Winter Average Energy Super Off-Peak %: 0.0%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 Solar Legacy Summer (May - October)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (C) - (B)	% (D) / (B)
200	31.26	38.28	7.02	22.5%
250	36.67	44.88	8.21	22.4%
300	42.08	51.49	9.41	22.4%
350	47.50	58.10	10.60	22.3%
400	52.91	64.70	11.79	22.3%
450	60.62	74.16	13.54	22.3%
500	68.34	83.61	15.27	22.3%
550	76.05	93.07	17.02	22.4%
600	83.77	102.53	18.76	22.4%
650	91.48	111.99	20.51	22.4%
700	99.20	121.44	22.24	22.4%
750	106.91	130.90	23.99	22.4%
800	114.63	140.36	25.73	22.4%
850	123.65	151.44	27.79	22.5%
900	132.68	162.52	29.84	22.5%
950	141.70	173.60	31.90	22.5%
1,000	150.72	184.68	33.96	22.5%
1,100	168.77	206.83	38.06	22.6%
1,200	186.81	228.99	42.18	22.6%
1,300	204.86	251.15	46.29	22.6%
1,400	222.91	273.31	50.40	22.6%
1,500	240.95	295.47	54.52	22.6%
1,600	259.00	317.62	58.62	22.6%
1,700	277.04	339.78	62.74	22.6%
1,800	295.09	361.94	66.85	22.7%
1,900	313.14	384.10	70.96	22.7%
2,000	331.18	406.26	75.08	22.7%
2,200	367.27	450.57	83.30	22.7%
2,400	403.37	494.89	91.52	22.7%
2,600	439.46	539.20	99.74	22.7%
2,800	475.55	583.52	107.97	22.7%
3,000	511.64	627.84	116.20	22.7%
4,000	704.05	864.23	160.18	22.8%
5,000	896.46	1,100.62	204.16	22.8%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 Solar Legacy Winter (November - April)

(A)	*(B)*	*(C)*	*(D)*	*(E)*
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) *(C) - (B)*	% *(D) / (B)*
200	30.66	37.53	6.87	22.4%
250	35.92	43.95	8.03	22.4%
300	41.18	50.37	9.19	22.3%
350	46.45	56.79	10.34	22.3%
400	51.71	63.21	11.50	22.2%
450	56.98	69.63	12.65	22.2%
500	62.24	76.06	13.82	22.2%
550	67.50	82.48	14.98	22.2%
600	72.77	88.90	16.13	22.2%
650	78.03	95.32	17.29	22.2%
700	83.30	101.74	18.44	22.1%
750	88.56	108.16	19.60	22.1%
800	93.82	114.58	20.76	22.1%
850	99.09	121.00	21.91	22.1%
900	104.35	127.42	23.07	22.1%
950	109.62	133.84	24.22	22.1%
1,000	114.88	140.26	25.38	22.1%
1,100	125.41	153.10	27.69	22.1%
1,200	135.94	165.94	30.00	22.1%
1,300	146.46	178.78	32.32	22.1%
1,400	156.99	191.62	34.63	22.1%
1,500	167.52	204.47	36.95	22.1%
1,600	178.05	217.31	39.26	22.0%
1,700	188.58	230.15	41.57	22.0%
1,800	199.10	242.99	43.89	22.0%
1,900	209.63	255.83	46.20	22.0%
2,000	220.16	268.67	48.51	22.0%
2,200	241.22	294.35	53.13	22.0%
2,400	262.27	320.03	57.76	22.0%
2,600	283.33	345.72	62.39	22.0%
2,800	304.38	371.40	67.02	22.0%
3,000	325.44	397.08	71.64	22.0%
4,000	430.72	525.49	94.77	22.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 Solar Legacy Summer (May - October)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (C) - (B)	% (D) / (B)
200	36.56	45.02	8.46	23.1%
250	40.89	50.31	9.42	23.0%
300	45.37	55.78	10.41	22.9%
350	49.84	61.23	11.39	22.9%
400	54.31	66.70	12.39	22.8%
450	58.79	72.17	13.38	22.8%
500	63.26	77.63	14.37	22.7%
550	67.74	83.09	15.35	22.7%
600	72.21	88.56	16.35	22.6%
650	76.69	94.02	17.33	22.6%
700	81.16	99.49	18.33	22.6%
750	85.50	104.79	19.29	22.6%
800	89.98	110.24	20.26	22.5%
850	94.45	115.71	21.26	22.5%
900	98.93	121.18	22.25	22.5%
950	103.40	126.64	23.24	22.5%
1,000	107.88	132.10	24.22	22.5%
1,100	116.82	143.03	26.21	22.4%
1,200	125.77	153.95	28.18	22.4%
1,300	134.58	164.72	30.14	22.4%
1,400	143.53	175.65	32.12	22.4%
1,500	152.48	186.57	34.09	22.4%
1,600	161.43	197.50	36.07	22.3%
1,700	170.24	208.26	38.02	22.3%
1,800	179.19	219.19	40.00	22.3%
1,900	188.14	230.11	41.97	22.3%
2,000	197.09	241.05	43.96	22.3%
2,200	214.85	262.73	47.88	22.3%
2,400	232.74	284.59	51.85	22.3%
2,600	250.64	306.44	55.80	22.3%
2,800	268.41	328.13	59.72	22.2%
3,000	286.31	349.99	63.68	22.2%

ET-1 Summer Average Energy On-Peak: 17.8%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 Solar Legacy Winter (November - April)

(A)	*(B)*	*(C)*	*(D)*	*(E)*
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) *(C) - (B)*	% *(D) / (B)*
200	33.32	40.98	7.66	23.0%
250	36.93	45.37	8.44	22.9%
300	40.64	49.89	9.25	22.8%
350	44.25	54.28	10.03	22.7%
400	47.97	58.80	10.83	22.6%
450	51.58	63.19	11.61	22.5%
500	55.20	67.59	12.39	22.4%
550	58.91	72.10	13.19	22.4%
600	62.53	76.49	13.96	22.3%
650	66.24	81.02	14.78	22.3%
700	69.86	85.41	15.55	22.3%
750	73.56	89.92	16.36	22.2%
800	77.18	94.31	17.13	22.2%
850	80.89	98.83	17.94	22.2%
900	84.51	103.22	18.71	22.1%
950	88.12	107.61	19.49	22.1%
1,000	91.84	112.13	20.29	22.1%
1,100	99.17	121.04	21.87	22.1%
1,200	106.49	129.96	23.47	22.0%
1,300	113.72	138.74	25.02	22.0%
1,400	121.05	147.65	26.60	22.0%
1,500	128.38	156.56	28.18	22.0%
1,600	135.71	165.47	29.76	21.9%
1,700	143.03	174.37	31.34	21.9%
1,800	150.36	183.29	32.93	21.9%
1,900	157.69	192.19	34.50	21.9%
2,000	165.02	201.11	36.09	21.9%
2,200	179.56	218.80	39.24	21.9%
2,400	194.23	236.62	42.39	21.8%
2,600	208.88	254.44	45.56	21.8%
2,800	223.54	272.26	48.72	21.8%
3,000	238.19	290.08	51.89	21.8%

ET-1 Winter Average Energy On-Peak: 10.9%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 Solar Legacy Summer (May - October)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (C) - (B)	% (D) / (B)
200	37.16	45.77	8.61	23.2%
250	41.64	51.23	9.59	23.0%
300	46.31	56.94	10.63	23.0%
350	50.99	62.66	11.67	22.9%
400	55.47	68.12	12.65	22.8%
450	60.14	73.84	13.70	22.8%
500	64.81	79.55	14.74	22.7%
550	69.29	85.01	15.72	22.7%
600	73.97	90.73	16.76	22.7%
650	78.65	96.44	17.79	22.6%
700	83.12	101.90	18.78	22.6%
750	87.79	107.62	19.83	22.6%
800	92.47	113.34	20.87	22.6%
850	97.15	119.04	21.89	22.5%
900	101.62	124.51	22.89	22.5%
950	106.30	130.22	23.92	22.5%
1,000	110.98	135.93	24.95	22.5%
1,100	120.12	147.11	26.99	22.5%
1,200	129.28	158.30	29.02	22.4%
1,300	138.63	169.72	31.09	22.4%
1,400	147.78	180.89	33.11	22.4%
1,500	156.93	192.07	35.14	22.4%
1,600	166.29	203.50	37.21	22.4%
1,700	175.43	214.68	39.25	22.4%
1,800	184.59	225.85	41.26	22.4%
1,900	193.94	237.29	43.35	22.4%
2,000	203.09	248.46	45.37	22.3%
2,200	221.60	271.07	49.47	22.3%
2,400	240.10	293.68	53.58	22.3%
2,600	258.40	316.03	57.63	22.3%
2,800	276.91	338.64	61.73	22.3%
3,000	295.41	361.24	65.83	22.3%

ET-2 Summer Average Energy On-Peak: 11%

Supporting Schedules: N/A

Recap Schedules: N/A

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 Solar Legacy Winter (November - April)

(A)	*(B)*	*(C)*	*(D)*	*(E)*
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) *(C) - (B)*	% *(D) / (B)*
200	34.27	42.17	7.90	23.1%
250	38.30	47.07	8.77	22.9%
300	42.17	51.78	9.61	22.8%
350	46.03	56.48	10.45	22.7%
400	49.90	61.18	11.28	22.6%
450	53.91	66.08	12.17	22.6%
500	57.78	70.79	13.01	22.5%
550	61.64	75.49	13.85	22.5%
600	65.67	80.39	14.72	22.4%
650	69.54	85.10	15.56	22.4%
700	73.40	89.80	16.40	22.3%
750	77.42	94.70	17.28	22.3%
800	81.28	99.40	18.12	22.3%
850	85.15	104.11	18.96	22.3%
900	89.02	108.81	19.79	22.2%
950	93.03	113.71	20.68	22.2%
1,000	96.91	118.42	21.51	22.2%
1,100	104.79	128.02	23.23	22.2%
1,200	112.52	137.43	24.91	22.1%
1,300	120.40	147.03	26.63	22.1%
1,400	128.30	156.63	28.33	22.1%
1,500	136.03	166.04	30.01	22.1%
1,600	143.91	175.65	31.74	22.1%
1,700	151.64	185.06	33.42	22.0%
1,800	159.53	194.66	35.13	22.0%
1,900	167.41	204.26	36.85	22.0%
2,000	175.14	213.67	38.53	22.0%
2,200	190.77	232.68	41.91	22.0%
2,400	206.53	251.88	45.35	22.0%
2,600	222.16	270.90	48.74	21.9%
2,800	237.77	289.92	52.15	21.9%
3,000	253.39	308.93	55.54	21.9%

ET-2 Winter Average Energy On-Peak: 6.6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R Solar Legacy Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
3	20%	438	88.80	109.29	20.49	23.1%
3	30%	657	101.11	124.11	23.00	22.7%
3	40%	876	113.43	138.94	25.51	22.5%
3	50%	1,095	125.70	153.73	28.03	22.3%
3	75%	1,643	156.52	190.86	34.34	21.9%
5	20%	730	135.54	166.72	31.18	23.0%
5	30%	1,095	156.04	191.41	35.37	22.7%
5	40%	1,460	176.57	216.15	39.58	22.4%
5	50%	1,825	197.07	240.84	43.77	22.2%
5	75%	2,738	248.39	302.65	54.26	21.8%
8	20%	1,168	205.68	252.89	47.21	23.0%
8	30%	1,752	238.49	292.41	53.92	22.6%
8	40%	2,336	271.30	331.94	60.64	22.4%
8	50%	2,920	304.15	371.51	67.36	22.1%
8	75%	4,380	386.21	470.34	84.13	21.8%
10	20%	1,460	252.42	310.34	57.92	22.9%
10	30%	2,190	293.45	359.76	66.31	22.6%
10	40%	2,920	334.49	409.19	74.70	22.3%
10	50%	3,650	375.52	458.60	83.08	22.1%
10	75%	5,475	478.08	582.14	104.06	21.8%
12	20%	1,752	299.17	367.77	68.60	22.9%
12	30%	2,628	348.42	427.10	78.68	22.6%
12	40%	3,504	397.64	486.38	88.74	22.3%
12	50%	4,380	446.89	545.70	98.81	22.1%
12	75%	6,570	569.95	693.93	123.98	21.8%
15	20%	2,190	369.30	453.96	84.66	22.9%
15	30%	3,285	430.84	528.07	97.23	22.6%
15	40%	4,380	492.40	602.22	109.82	22.3%
15	50%	5,475	553.93	676.34	122.41	22.1%
15	75%	8,213	707.81	861.69	153.88	21.7%

ECT-1R Summer Average Energy On-Peak %: 27.8%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R Solar Legacy Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
			Monthly Bill under	Monthly Bill under	Change	
kW	Load Factor	Monthly kWh	Present Rates	Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
3	20%	438	71.58	87.91	16.33	22.8%
3	30%	657	82.25	100.68	18.43	22.4%
3	40%	876	92.92	113.48	20.56	22.1%
3	50%	1,095	103.60	126.28	22.68	21.9%
3	75%	1,643	130.30	158.29	27.99	21.5%
5	20%	730	106.85	131.09	24.24	22.7%
5	30%	1,095	124.65	152.42	27.77	22.3%
5	40%	1,460	142.43	173.74	31.31	22.0%
5	50%	1,825	160.22	195.07	34.85	21.8%
5	75%	2,738	204.71	248.40	43.69	21.3%
8	20%	1,168	159.77	195.90	36.13	22.6%
8	30%	1,752	188.24	230.01	41.77	22.2%
8	40%	2,336	216.71	264.15	47.44	21.9%
8	50%	2,920	245.16	298.25	53.09	21.7%
8	75%	4,380	316.31	383.54	67.23	21.3%
10	20%	1,460	195.05	239.09	44.04	22.6%
10	30%	2,190	230.64	281.75	51.11	22.2%
10	40%	2,920	266.21	324.39	58.18	21.9%
10	50%	3,650	301.78	367.04	65.26	21.6%
10	75%	5,475	390.73	473.66	82.93	21.2%
12	20%	1,752	230.34	282.29	51.95	22.6%
12	30%	2,628	273.02	333.47	60.45	22.1%
12	40%	3,504	315.72	384.65	68.93	21.8%
12	50%	4,380	358.41	435.82	77.41	21.6%
12	75%	6,570	465.14	563.77	98.63	21.2%
15	20%	2,190	283.26	347.10	63.84	22.5%
15	30%	3,285	336.63	411.07	74.44	22.1%
15	40%	4,380	389.98	475.03	85.05	21.8%
15	50%	5,475	443.35	539.01	95.66	21.6%
15	75%	8,213	576.80	698.99	122.19	21.2%

ECT-1R Winter Average Energy On-Peak %: 21.8%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 Solar Legacy Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (E) - (D)	Change % (F) / (D)
3	20%	438	88.83	109.30	20.47	23.0%
3	30%	657	101.27	124.30	23.03	22.7%
3	40%	876	113.71	139.28	25.57	22.5%
3	50%	1,095	126.15	154.27	28.12	22.3%
3	75%	1,643	157.25	191.73	34.48	21.9%
5	20%	730	135.59	166.76	31.17	23.0%
5	30%	1,095	156.34	191.76	35.42	22.7%
5	40%	1,460	177.04	216.69	39.65	22.4%
5	50%	1,825	197.79	241.69	43.90	22.2%
5	75%	2,738	249.64	304.16	54.52	21.8%
8	20%	1,168	205.76	252.95	47.19	22.9%
8	30%	1,752	238.90	292.87	53.97	22.6%
8	40%	2,336	272.09	332.87	60.78	22.3%
8	50%	2,920	305.23	372.79	67.56	22.1%
8	75%	4,380	388.13	472.66	84.53	21.8%
10	20%	1,460	252.52	310.40	57.88	22.9%
10	30%	2,190	293.97	360.34	66.37	22.6%
10	40%	2,920	335.42	410.28	74.86	22.3%
10	50%	3,650	376.87	460.22	83.35	22.1%
10	75%	5,475	480.52	585.09	104.57	21.8%
12	20%	1,752	299.28	367.85	68.57	22.9%
12	30%	2,628	349.04	427.81	78.77	22.6%
12	40%	3,504	398.80	487.76	88.96	22.3%
12	50%	4,380	448.51	547.64	99.13	22.1%
12	75%	6,570	572.91	697.51	124.60	21.7%
15	20%	2,190	369.45	454.06	84.61	22.9%
15	30%	3,285	431.65	529.00	97.35	22.6%
15	40%	4,380	493.80	603.87	110.07	22.3%
15	50%	5,475	556.00	678.81	122.81	22.1%
15	75%	8,213	711.50	866.15	154.65	21.7%

ECT-2 Summer Average Energy On-Peak: 14%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 Solar Legacy Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
3	20%	438	70.94	87.09	16.15	22.8%
3	30%	657	81.50	99.74	18.24	22.4%
3	40%	876	92.04	112.37	20.33	22.1%
3	50%	1,095	102.58	124.99	22.41	21.8%
3	75%	1,643	128.97	156.62	27.65	21.4%
5	20%	730	105.81	129.77	23.96	22.6%
5	30%	1,095	123.38	150.82	27.44	22.2%
5	40%	1,460	140.96	171.89	30.93	21.9%
5	50%	1,825	158.54	192.94	34.40	21.7%
5	75%	2,738	202.50	245.62	43.12	21.3%
8	20%	1,168	158.10	193.78	35.68	22.6%
8	30%	1,752	186.21	227.47	41.26	22.2%
8	40%	2,336	214.33	261.15	46.82	21.8%
8	50%	2,920	242.44	294.84	52.40	21.6%
8	75%	4,380	312.75	379.07	66.32	21.2%
10	20%	1,460	192.95	236.44	43.49	22.5%
10	30%	2,190	228.10	278.55	50.45	22.1%
10	40%	2,920	263.24	320.66	57.42	21.8%
10	50%	3,650	298.39	362.78	64.39	21.6%
10	75%	5,475	386.28	468.07	81.79	21.2%
12	20%	1,752	227.81	279.11	51.30	22.5%
12	30%	2,628	270.00	329.65	59.65	22.1%
12	40%	3,504	312.18	380.19	68.01	21.8%
12	50%	4,380	354.35	430.71	76.36	21.5%
12	75%	6,570	459.81	557.07	97.26	21.2%
15	20%	2,190	280.10	343.11	63.01	22.5%
15	30%	3,285	332.82	406.27	73.45	22.1%
15	40%	4,380	385.55	469.45	83.90	21.8%
15	50%	5,475	438.28	532.63	94.35	21.5%
15	75%	8,213	570.11	690.57	120.46	21.1%

ECT-2 Winter Average Energy On-Peak: 10%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Bills are calculated based on the high end of the kWh block.
3) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-20 Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (E) - (D)	Change % (F) / (D)
15	20%	2,190	330.21	407.61	77.40	23.4%
15	30%	3,285	438.16	545.13	106.97	24.4%
15	40%	4,380	546.11	682.65	136.54	25.0%
15	50%	5,475	653.98	820.08	166.10	25.4%
15	75%	8,213	923.85	1,163.87	240.02	26.0%
30	20%	4,380	602.54	742.77	140.23	23.3%
30	30%	6,570	818.36	1,017.72	199.36	24.4%
30	40%	8,760	1,034.25	1,292.76	258.51	25.0%
30	50%	10,950	1,250.08	1,567.71	317.63	25.4%
30	75%	16,425	1,789.66	2,255.12	465.46	26.0%
50	20%	7,300	965.57	1,189.56	223.99	23.2%
50	30%	10,950	1,325.32	1,647.87	322.55	24.3%
50	40%	14,600	1,685.07	2,106.17	421.10	25.0%
50	50%	18,250	2,044.82	2,564.48	519.66	25.4%
50	75%	27,375	2,944.17	3,710.21	766.04	26.0%
100	20%	14,600	1,873.17	2,306.57	433.40	23.1%
100	30%	21,900	2,592.67	3,223.19	630.52	24.3%
100	40%	29,200	3,312.18	4,139.82	827.64	25.0%
100	50%	36,500	4,031.69	5,056.43	1,024.74	25.4%
100	75%	54,750	5,830.45	7,347.98	1,517.53	26.0%
150	20%	21,900	2,780.77	3,423.59	642.82	23.1%
150	30%	32,850	3,860.04	4,798.53	938.49	24.3%
150	40%	43,800	4,939.29	6,173.45	1,234.16	25.0%
150	50%	54,750	6,018.55	7,548.38	1,529.83	25.4%
150	75%	82,125	8,716.66	10,985.65	2,268.99	26.0%

General Service TOU Average Energy On-Peak: 34.22%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-20 Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (E) - (D)	Change % (F) / (D)
15	20%	2,190	298.84	367.59	68.75	23.0%
15	30%	3,285	391.03	485.02	93.99	24.0%
15	40%	4,380	483.23	602.45	119.22	24.7%
15	50%	5,475	575.48	719.95	144.47	25.1%
15	75%	8,213	806.06	1,013.64	207.58	25.8%
30	20%	4,380	539.66	662.57	122.91	22.8%
30	30%	6,570	724.11	897.50	173.39	23.9%
30	40%	8,760	908.57	1,132.44	223.87	24.6%
30	50%	10,950	1,092.95	1,367.28	274.33	25.1%
30	75%	16,425	1,554.04	1,954.58	400.54	25.8%
50	20%	7,300	860.84	1,055.97	195.13	22.7%
50	30%	10,950	1,168.19	1,447.44	279.25	23.9%
50	40%	14,600	1,475.60	1,839.00	363.40	24.6%
50	50%	18,250	1,782.96	2,230.47	447.51	25.1%
50	75%	27,375	2,551.47	3,209.33	657.86	25.8%
100	20%	14,600	1,663.70	2,039.40	375.70	22.6%
100	30%	21,900	2,278.48	2,822.43	543.95	23.9%
100	40%	29,200	2,893.25	3,605.46	712.21	24.6%
100	50%	36,500	3,508.03	4,388.50	880.47	25.1%
100	75%	54,750	5,044.92	6,346.04	1,301.12	25.8%
150	20%	21,900	2,466.58	3,022.83	556.25	22.6%
150	30%	32,850	3,388.71	4,197.34	808.63	23.9%
150	40%	43,800	4,310.89	5,371.93	1,061.04	24.6%
150	50%	54,750	5,233.02	6,546.44	1,313.42	25.1%
150	75%	82,125	7,538.43	9,482.82	1,944.39	25.8%

General Service TOU Average Energy On-Peak: 29%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-30 Summer (May - October)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
			(C) - (B)	(D) / (B)
30	15.75	19.56	3.81	24.2%
40	17.09	21.21	4.12	24.1%
50	18.43	22.86	4.43	24.0%
60	19.77	24.51	4.74	24.0%
70	21.11	26.16	5.05	23.9%
80	22.45	27.80	5.35	23.8%
90	23.80	29.45	5.65	23.7%
100	25.14	31.10	5.96	23.7%
125	28.49	35.23	6.74	23.7%
150	31.84	39.35	7.51	23.6%
175	35.19	43.47	8.28	23.5%
200	38.54	47.60	9.06	23.5%
225	41.89	51.72	9.83	23.5%
250	45.25	55.84	10.59	23.4%
275	48.60	59.97	11.37	23.4%
300	51.95	64.09	12.14	23.4%
325	55.30	68.21	12.91	23.3%
350	58.65	72.34	13.69	23.3%
375	62.00	76.46	14.46	23.3%
400	65.35	80.58	15.23	23.3%
425	68.71	84.71	16.00	23.3%
450	72.06	88.83	16.77	23.3%
475	75.41	92.95	17.54	23.3%
500	78.76	97.08	18.32	23.3%
600	92.17	113.57	21.40	23.2%
700	105.57	130.06	24.49	23.2%
800	118.98	146.55	27.57	23.2%
900	132.38	163.05	30.67	23.2%
1,000	145.79	179.54	33.75	23.1%
1,500	212.82	262.01	49.19	23.1%
2,000	279.85	344.47	64.62	23.1%
2,500	346.88	426.94	80.06	23.1%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-30 Winter (November - April)

(A)	*(B)*	*(C)*	*(D)*	*(E)*
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) *(C) - (B)*	% *(D) / (B)*
30	15.36	19.07	3.71	24.2%
40	16.57	20.56	3.99	24.1%
50	17.78	22.05	4.27	24.0%
60	18.99	23.53	4.54	23.9%
70	20.20	25.02	4.82	23.9%
80	21.41	26.51	5.10	23.8%
90	22.63	28.00	5.37	23.7%
100	23.84	29.48	5.64	23.7%
125	26.86	33.20	6.34	23.6%
150	29.89	36.92	7.03	23.5%
175	32.92	40.64	7.72	23.5%
200	35.94	44.36	8.42	23.4%
225	38.97	48.08	9.11	23.4%
250	42.00	51.80	9.80	23.3%
275	45.02	55.51	10.49	23.3%
300	48.05	59.23	11.18	23.3%
325	51.07	62.95	11.88	23.3%
350	54.10	66.67	12.57	23.2%
375	57.13	70.39	13.26	23.2%
400	60.15	74.11	13.96	23.2%
425	63.18	77.82	14.64	23.2%
450	66.21	81.54	15.33	23.2%
475	69.23	85.26	16.03	23.2%
500	72.26	88.98	16.72	23.1%
600	84.37	103.85	19.48	23.1%
700	96.47	118.73	22.26	23.1%
800	108.58	133.60	25.02	23.0%
900	120.68	148.48	27.80	23.0%
1,000	132.79	163.35	30.56	23.0%
1,500	193.32	237.72	44.40	23.0%
2,000	253.85	312.09	58.24	22.9%
2,500	314.38	386.46	72.08	22.9%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
5	15%	548	105.11	130.44	25.33	24.1%
5	30%	1,095	176.79	219.05	42.26	23.9%
5	45%	1,643	248.60	307.82	59.22	23.8%
5	60%	2,190	320.28	396.43	76.15	23.8%
5	75%	2,738	392.09	485.20	93.11	23.7%
10	15%	1,095	176.79	219.05	42.26	23.9%
10	30%	2,190	320.28	396.43	76.15	23.8%
10	45%	3,285	463.77	573.81	110.04	23.7%
10	60%	4,380	607.26	751.19	143.93	23.7%
10	75%	5,475	723.17	894.04	170.87	23.6%
15	15%	1,643	248.60	307.82	59.22	23.8%
15	30%	3,285	463.77	573.81	110.04	23.7%
15	45%	4,928	679.07	839.96	160.89	23.7%
15	60%	6,570	803.08	991.82	188.74	23.5%
15	75%	8,213	922.98	1,138.54	215.56	23.4%
20	15%	2,190	320.28	396.43	76.15	23.8%
20	30%	4,380	607.26	751.19	143.93	23.7%
20	45%	6,570	803.08	991.82	188.74	23.5%
20	60%	8,760	962.90	1,187.39	224.49	23.3%
20	75%	10,950	1,122.73	1,382.96	260.23	23.2%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
5	15%	548	96.47	119.63	23.16	24.0%
5	30%	1,095	159.52	197.46	37.94	23.8%
5	45%	1,643	222.69	275.42	52.73	23.7%
5	60%	2,190	285.74	353.24	67.50	23.6%
5	75%	2,738	348.91	431.21	82.30	23.6%
10	15%	1,095	159.52	197.46	37.94	23.8%
10	30%	2,190	285.74	353.24	67.50	23.6%
10	45%	3,285	411.96	509.03	97.07	23.6%
10	60%	4,380	538.18	664.81	126.63	23.5%
10	75%	5,475	636.67	785.87	149.20	23.4%
15	15%	1,643	222.69	275.42	52.73	23.7%
15	30%	3,285	411.96	509.03	97.07	23.6%
15	45%	4,928	601.35	742.78	141.43	23.5%
15	60%	6,570	698.97	861.60	162.63	23.3%
15	75%	8,213	792.44	975.23	182.79	23.1%
20	15%	2,190	285.74	353.24	67.50	23.6%
20	30%	4,380	538.18	664.81	126.63	23.5%
20	45%	6,570	698.97	861.60	162.63	23.3%
20	60%	8,760	823.56	1,013.06	189.50	23.0%
20	75%	10,950	948.15	1,164.52	216.37	22.8%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS D Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
5	15%	548	122.99	153.10	30.11	24.5%
5	30%	1,095	179.14	222.44	43.30	24.2%
5	45%	1,643	235.40	291.91	56.51	24.0%
5	60%	2,190	291.56	361.24	69.68	23.9%
5	75%	2,738	347.81	430.71	82.90	23.8%
10	15%	1,095	212.57	264.40	51.83	24.4%
10	30%	2,190	324.99	403.20	78.21	24.1%
10	45%	3,285	437.40	542.01	104.61	23.9%
10	60%	4,380	549.81	680.81	131.00	23.8%
10	75%	5,475	662.22	819.61	157.39	23.8%
15	15%	1,643	302.26	375.84	73.58	24.3%
15	30%	3,285	470.83	583.98	113.15	24.0%
15	45%	4,928	639.50	792.24	152.74	23.9%
15	60%	6,570	808.07	1,000.38	192.31	23.8%
15	75%	8,213	976.74	1,208.65	231.91	23.7%
20	15%	2,190	391.85	487.13	95.28	24.3%
20	30%	4,380	616.67	764.74	148.07	24.0%
20	45%	6,570	841.50	1,042.34	200.84	23.9%
20	60%	8,760	1,066.32	1,319.95	253.63	23.8%
20	75%	10,950	1,291.15	1,597.55	306.40	23.7%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS D Winter (November - April)

(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) *(E) - (D)*	% *(F) / (D)*
5	15%	548	112.84	140.36	27.52	24.4%
5	30%	1,095	158.86	196.97	38.11	24.0%
5	45%	1,643	204.97	253.69	48.72	23.8%
5	60%	2,190	251.00	310.31	59.31	23.6%
5	75%	2,738	297.11	367.02	69.91	23.5%
10	15%	1,095	192.29	238.93	46.64	24.3%
10	30%	2,190	284.43	352.27	67.84	23.9%
10	45%	3,285	376.56	465.60	89.04	23.6%
10	60%	4,380	468.69	578.93	110.24	23.5%
10	75%	5,475	560.83	692.26	131.43	23.4%
15	15%	1,643	271.83	337.62	65.79	24.2%
15	30%	3,285	409.99	507.57	97.58	23.8%
15	45%	4,928	548.23	677.62	129.39	23.6%
15	60%	6,570	686.39	847.57	161.18	23.5%
15	75%	8,213	824.63	1,017.62	192.99	23.4%
20	15%	2,190	351.29	436.20	84.91	24.2%
20	30%	4,380	535.55	662.86	127.31	23.8%
20	45%	6,570	719.82	889.53	169.71	23.6%
20	60%	8,760	904.09	1,116.19	212.10	23.5%
20	75%	10,950	1,088.35	1,342.86	254.51	23.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Sstandard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 S Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
21	15%	2,300	502.62	616.54	113.92	22.7%
21	30%	4,599	724.23	895.24	171.01	23.6%
21	45%	6,899	872.81	1,082.03	209.22	24.0%
21	60%	9,198	1,021.32	1,268.73	247.41	24.2%
21	75%	11,498	1,169.90	1,455.51	285.61	24.4%
40	15%	4,380	927.15	1,136.53	209.38	22.6%
40	30%	8,760	1,349.36	1,667.51	318.15	23.6%
40	45%	13,140	1,632.30	2,023.21	390.91	23.9%
40	60%	17,520	1,915.25	2,378.91	463.66	24.2%
40	75%	21,900	2,198.20	2,734.61	536.41	24.4%
60	15%	6,570	1,374.07	1,683.96	309.89	22.6%
60	30%	13,140	2,007.38	2,480.43	473.05	23.6%
60	45%	19,710	2,431.81	3,013.98	582.17	23.9%
60	60%	26,280	2,856.23	3,547.53	691.30	24.2%
60	75%	32,850	3,280.65	4,081.08	800.43	24.4%
80	15%	8,760	1,820.99	2,231.39	410.40	22.5%
80	30%	17,520	2,665.41	3,293.35	627.94	23.6%
80	45%	26,280	3,231.31	4,004.75	773.44	23.9%
80	60%	35,040	3,797.20	4,716.15	918.95	24.2%
80	75%	43,800	4,363.10	5,427.55	1,064.45	24.4%
90	15%	9,855	2,044.45	2,505.10	460.65	22.5%
90	30%	19,710	2,994.43	3,699.81	705.38	23.6%
90	45%	29,565	3,631.06	4,500.13	869.07	23.9%
90	60%	39,420	4,267.69	5,300.46	1,032.77	24.2%
90	75%	49,275	4,904.33	6,100.78	1,196.45	24.4%
100	15%	10,950	2,267.92	2,778.82	510.90	22.5%
100	30%	21,900	3,323.44	4,106.27	782.83	23.6%
100	45%	32,850	4,030.81	4,995.52	964.71	23.9%
100	60%	43,800	4,738.18	5,884.77	1,146.59	24.2%
100	75%	54,750	5,445.55	6,774.02	1,328.47	24.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 S Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
21	15%	2,300	467.57	572.43	104.86	22.4%
21	30%	4,599	654.15	807.03	152.88	23.4%
21	45%	6,899	767.70	949.73	182.03	23.7%
21	60%	9,198	881.20	1,092.36	211.16	24.0%
21	75%	11,498	994.75	1,235.05	240.30	24.2%
40	15%	4,380	860.40	1,052.52	192.12	22.3%
40	30%	8,760	1,215.86	1,499.50	283.64	23.3%
40	45%	13,140	1,432.10	1,771.24	339.14	23.7%
40	60%	17,520	1,648.34	2,042.97	394.63	23.9%
40	75%	21,900	1,864.58	2,314.71	450.13	24.1%
60	15%	6,570	1,273.94	1,557.95	284.01	22.3%
60	30%	13,140	1,807.14	2,228.42	421.28	23.3%
60	45%	19,710	2,131.50	2,636.02	504.52	23.7%
60	60%	26,280	2,455.86	3,043.62	587.76	23.9%
60	75%	32,850	2,780.22	3,451.22	671.00	24.1%
80	15%	8,760	1,687.49	2,063.37	375.88	22.3%
80	30%	17,520	2,398.42	2,957.33	558.91	23.3%
80	45%	26,280	2,830.90	3,500.80	669.90	23.7%
80	60%	35,040	3,263.38	4,044.27	780.89	23.9%
80	75%	43,800	3,695.87	4,587.74	891.87	24.1%
90	15%	9,855	1,894.26	2,316.08	421.82	22.3%
90	30%	19,710	2,694.06	3,321.79	627.73	23.3%
90	45%	29,565	3,180.60	3,933.19	752.59	23.7%
90	60%	39,420	3,667.15	4,544.60	877.45	23.9%
90	75%	49,275	4,153.69	5,156.00	1,002.31	24.1%
			-	-		
100	15%	10,950	2,101.04	2,568.80	467.76	22.3%
100	30%	21,900	2,989.70	3,686.25	696.55	23.3%
100	45%	32,850	3,530.30	4,365.58	835.28	23.7%
100	60%	43,800	4,070.91	5,044.92	974.01	23.9%
100	75%	54,750	4,611.51	5,724.26	1,112.75	24.1%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 M Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
			Monthly Bill	Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
101	15%	11,060	2,349.20	2,881.86	532.66	22.7%
101	30%	22,119	3,388.31	4,189.42	801.11	23.6%
101	45%	33,179	4,075.14	5,053.32	978.18	24.0%
101	60%	44,238	4,761.90	5,917.14	1,155.24	24.3%
101	75%	55,298	5,448.73	6,781.03	1,332.30	24.5%
150	15%	16,425	3,220.14	3,941.73	721.59	22.4%
150	30%	32,850	4,763.45	5,883.75	1,120.30	23.5%
150	45%	49,275	5,783.44	7,166.71	1,383.27	23.9%
150	60%	65,700	6,803.43	8,449.67	1,646.24	24.2%
150	75%	82,125	7,823.42	9,732.62	1,909.20	24.4%
200	15%	21,900	4,108.90	5,023.29	914.39	22.3%
200	30%	43,800	6,166.64	7,612.66	1,446.02	23.4%
200	45%	65,700	7,526.63	9,323.27	1,796.64	23.9%
200	60%	87,600	8,886.62	11,033.88	2,147.26	24.2%
200	75%	109,500	10,246.61	12,744.49	2,497.88	24.4%
300	15%	32,850	5,886.41	7,186.42	1,300.01	22.1%
300	30%	65,700	8,973.03	11,070.47	2,097.44	23.4%
300	45%	98,550	11,013.02	13,636.38	2,623.36	23.8%
300	60%	131,400	13,053.00	16,202.29	3,149.29	24.1%
300	75%	164,250	15,092.99	18,768.21	3,675.22	24.4%
350	15%	38,325	6,775.17	8,267.98	1,492.81	22.0%
350	30%	76,650	10,376.23	12,799.37	2,423.14	23.4%
350	45%	114,975	12,756.21	15,792.94	3,036.73	23.8%
350	60%	153,300	15,136.19	18,786.50	3,650.31	24.1%
350	75%	191,625	17,516.17	21,780.07	4,263.90	24.3%
400	15%	43,800	7,663.93	9,349.55	1,685.62	22.0%
400	30%	87,600	11,779.42	14,528.28	2,748.86	23.3%
400	45%	131,400	14,499.40	17,949.49	3,450.09	23.8%
400	60%	175,200	17,219.38	21,370.71	4,151.33	24.1%
400	75%	219,000	19,939.36	24,791.93	4,852.57	24.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 M Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	*(F) / (D)*
101	15%	11,060	2,179.65	2,667.41	487.76	22.4%
101	30%	22,119	3,049.24	3,760.90	711.66	23.3%
101	45%	33,179	3,566.63	4,412.44	845.81	23.7%
101	60%	44,238	4,083.97	5,063.93	979.96	24.0%
101	75%	55,298	4,601.35	5,715.47	1,114.12	24.2%
			-	-		
150	15%	16,425	2,968.34	3,623.25	654.91	22.1%
150	30%	32,850	4,259.88	5,247.33	987.45	23.2%
150	45%	49,275	5,028.24	6,214.93	1,186.69	23.6%
150	60%	65,700	5,796.61	7,182.53	1,385.92	23.9%
150	75%	82,125	6,564.97	8,150.12	1,585.15	24.1%
			-	-		
200	15%	21,900	3,773.17	4,598.65	825.48	21.9%
200	30%	43,800	5,495.22	6,764.10	1,268.88	23.1%
200	45%	65,700	6,519.71	8,054.23	1,534.52	23.5%
200	60%	87,600	7,544.19	9,344.36	1,800.17	23.9%
200	75%	109,500	8,568.67	10,634.49	2,065.82	24.1%
			-	-		
300	15%	32,850	5,382.82	6,549.46	1,166.64	21.7%
300	30%	65,700	7,965.91	9,797.63	1,831.72	23.0%
300	45%	98,550	9,502.63	11,732.82	2,230.19	23.5%
300	60%	131,400	11,039.35	13,668.01	2,628.66	23.8%
300	75%	164,250	12,576.08	15,603.21	3,027.13	24.1%
			-	-		
350	15%	38,325	6,187.65	7,524.86	1,337.21	21.6%
350	30%	76,650	9,201.25	11,314.39	2,113.14	23.0%
350	45%	114,975	10,994.09	13,572.12	2,578.03	23.4%
350	60%	153,300	12,786.93	15,829.84	3,042.91	23.8%
350	75%	191,625	14,579.78	18,087.57	3,507.79	24.1%
			-	-		
400	15%	43,800	6,992.48	8,500.27	1,507.79	21.6%
400	30%	87,600	10,436.59	12,831.16	2,394.57	22.9%
400	45%	131,400	12,485.55	15,411.41	2,925.86	23.4%
400	60%	175,200	14,534.52	17,991.67	3,457.15	23.8%
400	75%	219,000	16,583.48	20,571.93	3,988.45	24.1%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 L Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
401	15%	43,910	9,874.40	12,184.46	2,310.06	23.4%
401	30%	87,819	12,183.13	15,100.90	2,917.77	23.9%
401	45%	131,729	14,491.92	18,017.40	3,525.48	24.3%
401	60%	175,638	16,800.66	20,933.84	4,133.18	24.6%
401	75%	219,548	19,109.44	23,850.34	4,740.90	24.8%
600	15%	65,700	14,355.36	17,700.50	3,345.14	23.3%
600	30%	131,400	17,809.86	22,064.30	4,254.44	23.9%
600	45%	197,100	21,264.37	26,428.09	5,163.72	24.3%
600	60%	262,800	24,718.87	30,791.89	6,073.02	24.6%
600	75%	328,500	28,173.38	35,155.68	6,982.30	24.8%
800	15%	87,600	18,858.86	23,244.30	4,385.44	23.3%
800	30%	175,200	23,464.87	29,062.69	5,597.82	23.9%
800	45%	262,800	28,070.87	34,881.09	6,810.22	24.3%
800	60%	350,400	32,676.88	40,699.48	8,022.60	24.6%
800	75%	438,000	37,282.89	46,517.87	9,234.98	24.8%
1,000	15%	109,500	23,362.36	28,788.10	5,425.74	23.2%
1,000	30%	219,000	29,119.87	36,061.09	6,941.22	23.8%
1,000	45%	328,500	34,877.38	43,334.08	8,456.70	24.2%
1,000	60%	438,000	40,634.89	50,607.07	9,972.18	24.5%
1,000	75%	547,500	46,392.40	57,880.06	11,487.66	24.8%
1,500	15%	164,250	34,621.12	42,647.60	8,026.48	23.2%
1,500	30%	328,500	43,257.38	53,557.08	10,299.70	23.8%
1,500	45%	492,750	51,893.65	64,466.57	12,572.92	24.2%
1,500	60%	657,000	60,529.91	75,376.05	14,846.14	24.5%
1,500	75%	821,250	69,166.18	86,285.54	17,119.36	24.8%
3,000	15%	328,500	68,397.38	84,226.08	15,828.70	23.1%
3,000	30%	657,000	85,669.91	106,045.05	20,375.14	23.8%
3,000	45%	985,500	102,942.44	127,864.02	24,921.58	24.2%
3,000	60%	1,314,000	120,214.97	149,682.99	29,468.02	24.5%
3,000	75%	1,642,500	137,487.50	171,501.96	34,014.46	24.7%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 L Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
401	15%	43,910	9,120.90	11,230.74	2,109.84	23.1%
401	30%	87,819	10,676.16	13,193.47	2,517.31	23.6%
401	45%	131,729	12,231.45	15,156.25	2,924.80	23.9%
401	60%	175,638	13,786.71	17,118.98	3,332.27	24.2%
401	75%	219,548	15,342.00	19,081.76	3,739.76	24.4%
600	15%	65,700	13,227.94	16,273.50	3,045.56	23.0%
600	30%	131,400	15,555.04	19,210.29	3,655.25	23.5%
600	45%	197,100	17,882.13	22,147.08	4,264.95	23.9%
600	60%	262,800	20,209.23	25,083.87	4,874.64	24.1%
600	75%	328,500	22,536.32	28,020.66	5,484.34	24.3%
800	15%	87,600	17,355.64	21,341.63	3,985.99	23.0%
800	30%	175,200	20,458.43	25,257.35	4,798.92	23.5%
800	45%	262,800	23,561.23	29,173.07	5,611.84	23.8%
800	60%	350,400	26,664.02	33,088.79	6,424.77	24.1%
800	75%	438,000	29,766.81	37,004.51	7,237.70	24.3%
1,000	15%	109,500	21,483.34	26,409.76	4,926.42	22.9%
1,000	30%	219,000	25,361.83	31,304.41	5,942.58	23.4%
1,000	45%	328,500	29,240.32	36,199.06	6,958.74	23.8%
1,000	60%	438,000	33,118.81	41,093.71	7,974.90	24.1%
1,000	75%	547,500	36,997.30	45,988.36	8,991.06	24.3%
1,500	15%	164,250	31,802.59	39,080.09	7,277.50	22.9%
1,500	30%	328,500	37,620.32	46,422.06	8,801.74	23.4%
1,500	45%	492,750	43,438.06	53,764.04	10,325.98	23.8%
1,500	60%	657,000	49,255.79	61,106.01	11,850.22	24.1%
1,500	75%	821,250	55,073.53	68,447.99	13,374.46	24.3%
3,000	15%	328,500	62,760.32	77,091.06	14,330.74	22.8%
3,000	30%	657,000	74,395.79	91,775.01	17,379.22	23.4%
3,000	45%	985,500	86,031.26	106,458.96	20,427.70	23.7%
3,000	60%	1,314,000	97,666.73	121,142.91	23,476.18	24.0%
3,000	75%	1,642,500	109,302.20	135,826.86	26,524.66	24.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
5	7.5	15%	821	169.21	210.28	41.07	24.3%
5	7.5	30%	1,643	264.48	327.97	63.49	24.0%
5	7.5	45%	2,464	359.65	445.52	85.87	23.9%
5	7.5	60%	3,285	454.83	563.08	108.25	23.8%
5	7.5	75%	4,106	549.96	680.59	130.63	23.8%
10	12	15%	1,314	259.58	322.51	62.93	24.2%
10	12	30%	2,628	411.87	510.61	98.74	24.0%
10	12	45%	3,942	564.18	698.76	134.58	23.9%
10	12	60%	5,256	716.51	886.90	170.39	23.8%
10	12	75%	6,570	868.79	1,075.01	206.22	23.7%
15	20	15%	2,190	403.10	500.54	97.44	24.2%
15	20	30%	4,380	656.93	814.09	157.16	23.9%
15	20	45%	6,570	910.78	1,127.64	216.86	23.8%
15	20	60%	8,760	1,164.62	1,441.19	276.57	23.7%
15	20	75%	10,950	1,418.47	1,754.74	336.27	23.7%
20	25	15%	2,738	501.07	622.19	121.12	24.2%
20	25	30%	5,475	818.34	1,014.09	195.75	23.9%
20	25	45%	8,213	1,135.70	1,406.08	270.38	23.8%
20	25	60%	10,950	1,452.94	1,797.94	345.00	23.7%
20	25	75%	13,688	1,770.32	2,189.98	419.66	23.7%

General Service TOU Average Energy On-Peak %: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Winter (November - April)

(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	*(G) / (E)*
5	7.5	15%	821	150.02	186.24	36.22	24.1%
5	7.5	30%	1,643	226.08	279.84	53.76	23.8%
5	7.5	45%	2,464	302.06	373.35	71.29	23.6%
5	7.5	60%	3,285	378.04	466.85	88.81	23.5%
5	7.5	75%	4,106	454.01	560.36	106.35	23.4%
10	12	15%	1,314	228.87	284.02	55.15	24.1%
10	12	30%	2,628	350.44	433.63	83.19	23.7%
10	12	45%	3,942	472.04	583.29	111.25	23.6%
10	12	60%	5,256	593.65	732.94	139.29	23.5%
10	12	75%	6,570	715.22	882.56	167.34	23.4%
15	20	15%	2,190	351.91	436.40	84.49	24.0%
15	20	30%	4,380	554.58	685.82	131.24	23.7%
15	20	45%	6,570	757.21	935.19	177.98	23.5%
15	20	60%	8,760	959.88	1,184.60	224.72	23.4%
15	20	75%	10,950	1,162.54	1,434.01	271.47	23.4%
20	25	15%	2,738	437.09	542.01	104.92	24.0%
20	25	30%	5,475	690.35	853.69	163.34	23.7%
20	25	45%	8,213	943.72	1,165.51	221.79	23.5%
20	25	60%	10,950	1,197.01	1,477.21	280.20	23.4%
20	25	75%	13,688	1,450.37	1,789.04	338.67	23.4%

General Service TOU Average Energy On-Peak %: 15%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Reequirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU S Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
21	30	15%	3,285	849.88	1,049.09	199.21	23.4%
21	30	30%	6,570	1,031.65	1,276.51	244.86	23.7%
21	30	45%	9,855	1,213.39	1,503.90	290.51	23.9%
21	30	60%	13,140	1,395.15	1,731.33	336.18	24.1%
21	30	75%	16,425	1,576.90	1,958.73	381.83	24.2%
40	50	15%	5,475	1,491.14	1,838.41	347.27	23.3%
40	50	30%	10,950	1,794.07	2,217.44	423.37	23.6%
40	50	45%	16,425	2,096.99	2,596.45	499.46	23.8%
40	50	60%	21,900	2,399.92	2,975.48	575.56	24.0%
40	50	75%	27,375	2,702.83	3,354.48	651.65	24.1%
60	70	15%	7,665	2,151.77	2,651.28	499.51	23.2%
60	70	30%	15,330	2,575.87	3,181.91	606.04	23.5%
60	70	45%	22,995	2,999.95	3,712.53	712.58	23.8%
60	70	60%	30,660	3,424.05	4,243.16	819.11	23.9%
60	70	75%	38,325	3,848.12	4,773.77	925.65	24.1%
80	100	15%	10,950	2,949.00	3,635.18	686.18	23.3%
80	100	30%	21,900	3,554.85	4,393.22	838.37	23.6%
80	100	45%	32,850	4,160.68	5,151.25	990.57	23.8%
80	100	60%	43,800	4,766.53	5,909.28	1,142.75	24.0%
80	100	75%	54,750	5,372.37	6,667.31	1,294.94	24.1%
90	110	15%	12,045	3,229.44	3,979.14	749.70	23.2%
90	110	30%	24,090	3,895.88	4,812.98	917.10	23.5%
90	110	45%	36,135	4,562.29	5,646.81	1,084.52	23.8%
90	110	60%	48,180	5,228.72	6,480.65	1,251.93	23.9%
90	110	75%	60,225	5,895.14	7,314.48	1,419.34	24.1%
100	120	15%	13,140	3,509.89	4,323.11	813.22	23.2%
100	120	30%	26,280	4,236.91	5,232.74	995.83	23.5%
100	120	45%	39,420	4,963.91	6,142.38	1,178.47	23.7%
100	120	60%	52,560	5,690.92	7,052.02	1,361.10	23.9%
100	120	75%	65,700	6,417.93	7,961.66	1,543.73	24.1%

General Service TOU Average Energy On-Peak %: 15%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU S Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
21	30	15%	3,285	806.65	994.95	188.30	23.3%
21	30	30%	6,570	945.15	1,168.22	223.07	23.6%
21	30	45%	9,855	1,083.66	1,341.48	257.82	23.8%
21	30	60%	13,140	1,222.16	1,514.74	292.58	23.9%
21	30	75%	16,425	1,360.67	1,688.01	327.34	24.1%
40	50	15%	5,475	1,419.07	1,748.18	329.11	23.2%
40	50	30%	10,950	1,649.91	2,036.94	387.03	23.5%
40	50	45%	16,425	1,880.76	2,325.73	444.97	23.7%
40	50	60%	21,900	2,111.60	2,614.49	502.89	23.8%
40	50	75%	27,375	2,342.44	2,903.26	560.82	23.9%
60	70	15%	7,665	2,050.87	2,524.94	474.07	23.1%
60	70	30%	15,330	2,374.05	2,929.23	555.18	23.4%
60	70	45%	22,995	2,697.23	3,333.49	636.26	23.6%
60	70	60%	30,660	3,020.41	3,737.77	717.36	23.8%
60	70	75%	38,325	3,343.59	4,142.04	798.45	23.9%
80	100	15%	10,950	2,804.84	3,454.68	649.84	23.2%
80	100	30%	21,900	3,266.53	4,032.23	765.70	23.4%
80	100	45%	32,850	3,728.21	4,609.75	881.54	23.6%
80	100	60%	43,800	4,189.90	5,187.29	997.39	23.8%
80	100	75%	54,750	4,651.58	5,764.84	1,113.26	23.9%
90	110	15%	12,045	3,070.87	3,780.60	709.73	23.1%
90	110	30%	24,090	3,578.73	4,415.90	837.17	23.4%
90	110	45%	36,135	4,086.58	5,051.18	964.60	23.6%
90	110	60%	48,180	4,594.43	5,686.47	1,092.04	23.8%
90	110	75%	60,225	5,102.29	6,321.76	1,219.47	23.9%
100	120	15%	13,140	3,336.90	4,106.52	769.62	23.1%
100	120	30%	26,280	3,890.92	4,799.56	908.64	23.4%
100	120	45%	39,420	4,444.95	5,492.60	1,047.65	23.6%
100	120	60%	52,560	4,998.97	6,185.65	1,186.68	23.7%
100	120	75%	65,700	5,552.99	6,878.69	1,325.70	23.9%

General Service TOU Average Energy On-Peak %: 14%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU M Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
101	120	15%	13,140	3,302.09	4,073.30	771.21	23.4%
101	120	30%	26,280	4,078.41	5,047.63	969.22	23.8%
101	120	45%	39,420	4,854.71	6,021.94	1,167.23	24.0%
101	120	60%	52,560	5,631.02	6,996.25	1,365.23	24.2%
101	120	75%	65,700	6,407.34	7,970.57	1,563.23	24.4%
				-	-		
150	170	15%	18,615	4,339.03	5,339.67	1,000.64	23.1%
150	170	30%	37,230	5,438.80	6,719.96	1,281.16	23.6%
150	170	45%	55,845	6,538.57	8,100.23	1,561.66	23.9%
150	170	60%	74,460	7,638.34	9,480.50	1,842.16	24.1%
150	170	75%	93,075	8,738.11	10,860.78	2,122.67	24.3%
200	220	15%	24,090	5,387.29	6,619.54	1,232.25	22.9%
200	220	30%	48,180	6,810.52	8,405.77	1,595.25	23.4%
200	220	45%	72,270	8,233.76	10,192.02	1,958.26	23.8%
200	220	60%	96,360	9,656.98	11,978.25	2,321.27	24.0%
200	220	75%	120,450	11,080.21	13,764.50	2,684.29	24.2%
300	320	15%	35,040	7,483.81	9,179.27	1,695.46	22.7%
300	320	30%	70,080	9,553.98	11,777.44	2,223.46	23.3%
300	320	45%	105,120	11,624.13	14,375.60	2,751.47	23.7%
300	320	60%	140,160	13,694.28	16,973.76	3,279.48	23.9%
300	320	75%	175,200	15,764.43	19,571.92	3,807.49	24.2%
350	370	15%	40,515	8,532.07	10,459.12	1,927.05	22.6%
350	370	30%	81,030	10,925.69	13,463.26	2,537.57	23.2%
350	370	45%	121,545	13,319.30	16,467.38	3,148.08	23.6%
350	370	60%	162,060	15,712.93	19,471.52	3,758.59	23.9%
350	370	75%	202,575	18,106.53	22,475.63	4,369.10	24.1%
400	420	15%	45,990	9,580.34	11,738.99	2,158.65	22.5%
400	420	30%	91,980	12,297.41	15,149.09	2,851.68	23.2%
400	420	45%	137,970	15,014.49	18,559.17	3,544.68	23.6%
400	420	60%	183,960	17,731.56	21,969.26	4,237.70	23.9%
400	420	75%	229,950	20,448.65	25,379.37	4,930.72	24.1%

General Service TOU Average Energy On-Peak %: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU M Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
101	120	15%	13,140	3,127.62	3,853.98	726.36	23.2%
101	120	30%	26,280	3,729.46	4,608.96	879.50	23.6%
101	120	45%	39,420	4,331.28	5,363.92	1,032.64	23.8%
101	120	60%	52,560	4,933.11	6,118.90	1,185.79	24.0%
101	120	75%	65,700	5,534.94	6,873.88	1,338.94	24.2%
150	170	15%	18,615	4,091.85	5,028.95	937.10	22.9%
150	170	30%	37,230	4,944.44	6,098.50	1,154.06	23.3%
150	170	45%	55,845	5,797.05	7,168.05	1,371.00	23.6%
150	170	60%	74,460	6,649.63	8,237.60	1,587.97	23.9%
150	170	75%	93,075	7,502.23	9,307.15	1,804.92	24.1%
200	220	15%	24,090	5,067.42	6,217.43	1,150.01	22.7%
200	220	30%	48,180	6,170.77	7,601.55	1,430.78	23.2%
200	220	45%	72,270	7,274.13	8,985.67	1,711.54	23.5%
200	220	60%	96,360	8,377.49	10,369.78	1,992.29	23.8%
200	220	75%	120,450	9,480.85	11,753.91	2,273.06	24.0%
300	320	15%	35,040	7,018.54	8,594.37	1,575.83	22.5%
300	320	30%	70,080	8,623.42	10,607.62	1,984.20	23.0%
300	320	45%	105,120	10,228.31	12,620.91	2,392.60	23.4%
300	320	60%	140,160	11,833.19	14,634.17	2,800.98	23.7%
300	320	75%	175,200	13,438.07	16,647.44	3,209.37	23.9%
350	370	15%	40,515	7,994.11	9,782.85	1,788.74	22.4%
350	370	30%	81,030	9,849.75	12,110.67	2,260.92	23.0%
350	370	45%	121,545	11,705.39	14,438.52	2,733.13	23.3%
350	370	60%	162,060	13,561.03	16,766.36	3,205.33	23.6%
350	370	75%	202,575	15,416.69	19,094.21	3,677.52	23.9%
400	420	15%	45,990	8,969.67	10,971.32	2,001.65	22.3%
400	420	30%	91,980	11,076.07	13,613.73	2,537.66	22.9%
400	420	45%	137,970	13,182.49	16,256.14	3,073.65	23.3%
400	420	60%	183,960	15,288.89	18,898.56	3,609.67	23.6%
400	420	75%	229,950	17,395.28	21,540.96	4,145.68	23.8%

General Service TOU Average Energy On-Peak %: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU L Summer (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
401	441	15%	48,290	9,595.45	11,818.02	2,222.57	23.2%
401	441	30%	96,579	12,325.83	15,263.16	2,937.33	23.8%
401	441	45%	144,869	15,056.25	18,708.35	3,652.10	24.3%
401	441	60%	193,158	17,786.62	22,153.49	4,366.87	24.6%
401	441	75%	241,448	20,517.05	25,598.69	5,081.64	24.8%
600	640	15%	70,080	13,705.64	16,859.48	3,153.84	23.0%
600	640	30%	140,160	17,668.12	21,859.26	4,191.14	23.7%
600	640	45%	210,240	21,630.60	26,859.05	5,228.45	24.2%
600	640	60%	280,320	25,593.08	31,858.84	6,265.76	24.5%
600	640	75%	350,400	29,555.57	36,858.64	7,303.07	24.7%
800	860	15%	94,170	18,023.91	22,162.89	4,138.98	23.0%
800	860	30%	188,340	23,348.49	28,881.36	5,532.87	23.7%
800	860	45%	282,510	28,673.07	35,599.83	6,926.76	24.2%
800	860	60%	376,680	33,997.65	42,318.30	8,320.65	24.5%
800	860	75%	470,850	39,322.23	49,036.76	9,714.53	24.7%
1,000	1,200	15%	131,400	23,466.49	28,885.81	5,419.32	23.1%
1,000	1,200	30%	262,800	30,896.15	38,260.42	7,364.27	23.8%
1,000	1,200	45%	394,200	38,325.79	47,635.03	9,309.24	24.3%
1,000	1,200	60%	525,600	45,755.43	57,009.62	11,254.19	24.6%
1,000	1,200	75%	657,000	53,185.08	66,384.22	13,199.14	24.8%
1,500	1,700	15%	186,150	33,793.68	41,552.90	7,759.22	23.0%
1,500	1,700	30%	372,300	44,319.02	54,833.60	10,514.58	23.7%
1,500	1,700	45%	558,450	54,844.35	68,114.28	13,269.93	24.2%
1,500	1,700	60%	744,600	65,369.67	81,394.96	16,025.29	24.5%
1,500	1,700	75%	930,750	75,895.00	94,675.64	18,780.64	24.7%
3,000	3,200	15%	350,400	64,775.25	79,554.16	14,778.91	22.8%
3,000	3,200	30%	700,800	84,587.63	104,553.10	19,965.47	23.6%
3,000	3,200	45%	1,051,200	104,400.02	129,552.05	25,152.03	24.1%
3,000	3,200	60%	1,401,600	124,212.40	154,550.98	30,338.58	24.4%
3,000	3,200	75%	1,752,000	144,024.80	179,549.92	35,525.12	24.7%

General Service TOU Average Energy On-Peak %: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU L Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
401	441	15%	48,290	8,927.88	10,974.30	2,046.42	22.9%
401	441	30%	96,579	10,990.67	13,575.73	2,585.06	23.5%
401	441	45%	144,869	13,053.50	16,177.20	3,123.70	23.9%
401	441	60%	193,158	15,116.29	18,778.63	3,662.34	24.2%
401	441	75%	241,448	17,179.13	21,380.10	4,200.97	24.5%
600	640	15%	70,080	12,736.82	15,635.03	2,898.21	22.8%
600	640	30%	140,160	15,730.48	19,410.39	3,679.91	23.4%
600	640	45%	210,240	18,724.13	23,185.73	4,461.60	23.8%
600	640	60%	280,320	21,717.78	26,961.09	5,243.31	24.1%
600	640	75%	350,400	24,711.43	30,736.44	6,025.01	24.4%
800	860	15%	94,170	16,722.05	20,517.56	3,795.51	22.7%
800	860	30%	188,340	20,744.78	25,590.69	4,845.91	23.4%
800	860	45%	282,510	24,767.49	30,663.80	5,896.31	23.8%
800	860	60%	376,680	28,790.21	35,736.93	6,946.72	24.1%
800	860	75%	470,850	32,812.93	40,810.06	7,997.13	24.4%
1,000	1,200	15%	131,400	21,649.94	26,589.98	4,940.04	22.8%
1,000	1,200	30%	262,800	27,263.05	33,668.77	6,405.72	23.5%
1,000	1,200	45%	394,200	32,876.14	40,747.54	7,871.40	23.9%
1,000	1,200	60%	525,600	38,489.25	47,826.33	9,337.08	24.3%
1,000	1,200	75%	657,000	44,102.34	54,905.12	10,802.78	24.5%
1,500	1,700	15%	186,150	31,220.24	38,300.49	7,080.25	22.7%
1,500	1,700	30%	372,300	39,172.13	48,328.76	9,156.63	23.4%
1,500	1,700	45%	558,450	47,124.01	58,357.02	11,233.01	23.8%
1,500	1,700	60%	744,600	55,075.90	68,385.29	13,309.39	24.2%
1,500	1,700	75%	930,750	63,027.79	78,413.57	15,385.78	24.4%
3,000	3,200	15%	350,400	59,931.11	73,431.96	13,500.85	22.5%
3,000	3,200	30%	700,800	74,899.38	92,308.70	17,409.32	23.2%
3,000	3,200	45%	1,051,200	89,867.63	111,185.45	21,317.82	23.7%
3,000	3,200	60%	1,401,600	104,835.89	130,062.20	25,226.31	24.1%
3,000	3,200	75%	1,752,000	119,804.15	148,938.94	29,134.79	24.3%

General Service TOU Average Energy On-Peak %: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-34

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
3,000	20%	438,000	77,646.54	96,480.09	18,833.55	24.3%
3,000	30%	657,000	85,749.54	106,803.75	21,054.21	24.6%
3,000	40%	876,000	93,852.54	117,127.41	23,274.87	24.8%
3,000	50%	1,095,000	101,955.54	127,451.07	25,495.53	25.0%
3,000	75%	1,642,500	122,213.04	153,260.22	31,047.18	25.4%
3,500	20%	511,000	90,563.54	112,529.31	21,965.77	24.3%
3,500	30%	766,500	100,017.04	124,573.58	24,556.54	24.6%
3,500	40%	1,022,000	109,470.54	136,617.85	27,147.31	24.8%
3,500	50%	1,277,500	118,924.04	148,662.12	29,738.08	25.0%
3,500	75%	1,916,250	142,557.79	178,772.80	36,215.01	25.4%
4,000	20%	584,000	103,480.54	128,578.53	25,097.99	24.3%
4,000	30%	876,000	114,284.54	142,343.41	28,058.87	24.6%
4,000	40%	1,168,000	125,088.54	156,108.29	31,019.75	24.8%
4,000	50%	1,460,000	135,892.54	169,873.17	33,980.63	25.0%
4,000	75%	2,190,000	162,902.54	204,285.37	41,382.83	25.4%
4,500	20%	657,000	116,397.54	144,627.75	28,230.21	24.3%
4,500	30%	985,500	128,552.04	160,113.24	31,561.20	24.6%
4,500	40%	1,314,000	140,706.54	175,598.73	34,892.19	24.8%
4,500	50%	1,642,500	152,861.04	191,084.22	38,223.18	25.0%
4,500	75%	2,463,750	183,247.29	229,797.95	46,550.66	25.4%
5,000	20%	730,000	129,314.54	160,676.97	31,362.43	24.3%
5,000	30%	1,095,000	142,819.54	177,883.07	35,063.53	24.6%
5,000	40%	1,460,000	156,324.54	195,089.17	38,764.63	24.8%
5,000	50%	1,825,000	169,829.54	212,295.27	42,465.73	25.0%
5,000	75%	2,737,500	203,592.04	255,310.52	51,718.48	25.4%
6,000	20%	876,000	155,148.54	192,775.41	37,626.87	24.3%
6,000	30%	1,314,000	171,354.54	213,422.73	42,068.19	24.6%
6,000	40%	1,752,000	187,560.54	234,070.05	46,509.51	24.8%
6,000	50%	2,190,000	203,766.54	254,717.37	50,950.83	25.0%
6,000	75%	3,285,000	244,281.54	306,335.67	62,054.13	25.4%
7,000	20%	1,022,000	180,982.54	224,873.85	43,891.31	24.3%
7,000	30%	1,533,000	199,889.54	248,962.39	49,072.85	24.5%
7,000	50%	2,555,000	237,703.54	297,139.47	59,435.93	25.0%
7,000	75%	3,832,500	284,971.04	357,360.82	72,389.78	25.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical General Service Bill Analysis at Present and Proposed Rates
E-35

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
3,000	4,000	20%	438,000	79,188.20	98,450.02	19,261.82	24.3%
3,000	4,000	30%	657,000	87,049.53	108,464.64	21,415.11	24.6%
3,000	4,000	40%	876,000	94,910.86	118,479.26	23,568.40	24.8%
3,000	4,000	50%	1,095,000	102,772.19	128,493.89	25,721.70	25.0%
3,000	4,000	75%	1,642,500	122,425.52	153,530.45	31,104.93	25.4%
3,500	4,500	20%	511,000	91,918.64	114,260.73	22,342.09	24.3%
3,500	4,500	30%	766,500	101,090.20	125,944.46	24,854.26	24.6%
3,500	4,500	40%	1,022,000	110,261.75	137,628.17	27,366.42	24.8%
3,500	4,500	50%	1,277,500	119,433.30	149,311.90	29,878.60	25.0%
3,500	4,500	75%	1,916,250	142,362.18	178,521.22	36,159.04	25.4%
4,000	5,000	20%	584,000	104,649.09	130,071.43	25,422.34	24.3%
4,000	5,000	30%	876,000	115,130.86	143,424.26	28,293.40	24.6%
4,000	5,000	40%	1,168,000	125,612.64	156,777.10	31,164.46	24.8%
4,000	5,000	50%	1,460,000	136,094.41	170,129.92	34,035.51	25.0%
4,000	5,000	75%	2,190,000	162,298.84	203,512.00	41,213.16	25.4%
4,500	6,000	20%	657,000	118,710.03	147,582.64	28,872.61	24.3%
4,500	6,000	30%	985,500	130,502.03	162,604.57	32,102.54	24.6%
4,500	6,000	40%	1,314,000	142,294.02	177,626.51	35,332.49	24.8%
4,500	6,000	50%	1,642,500	154,086.02	192,648.45	38,562.43	25.0%
4,500	6,000	75%	2,463,750	183,566.01	230,203.27	46,637.26	25.4%
5,000	7,000	20%	730,000	132,770.97	165,093.85	32,322.88	24.3%
5,000	7,000	30%	1,095,000	145,873.19	181,784.89	35,911.70	24.6%
5,000	7,000	40%	1,460,000	158,975.41	198,475.92	39,500.51	24.8%
5,000	7,000	50%	1,825,000	172,077.63	215,166.97	43,089.34	25.0%
5,000	7,000	75%	2,737,500	204,833.17	256,894.55	52,061.38	25.4%
6,000	8,000	20%	876,000	158,231.86	196,715.26	38,483.40	24.3%
6,000	8,000	30%	1,314,000	173,954.52	216,744.51	42,789.99	24.6%
6,000	8,000	40%	1,752,000	189,677.18	236,773.75	47,096.57	24.8%
6,000	8,000	50%	2,190,000	205,399.84	256,803.00	51,403.16	25.0%
6,000	8,000	75%	3,285,000	244,706.49	306,876.12	62,169.63	25.4%
7,000	8,500	20%	1,022,000	182,362.25	226,636.17	44,273.92	24.3%
7,000	8,500	30%	1,533,000	200,705.35	250,003.63	49,298.28	24.6%
7,000	8,500	40%	2,044,000	219,048.46	273,371.08	54,322.62	24.8%
7,000	8,500	50%	2,555,000	237,391.56	296,738.54	59,346.98	25.0%
7,000	8,500	75%	3,832,500	283,249.32	355,157.18	71,907.86	25.4%

E-35 Average Energy On-Peak %: 42%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
E-221

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
10	20%	1,460	189.38	238.91	49.53	26.2%
10	35%	2,555	265.93	340.13	74.20	27.9%
10	50%	3,650	342.48	441.35	98.87	28.9%
10	65%	4,745	419.03	542.57	123.54	29.5%
10	80%	5,840	495.59	643.79	148.20	29.9%
30	20%	4,380	486.54	613.47	126.93	26.1%
30	35%	7,665	716.19	917.14	200.95	28.1%
30	50%	10,950	945.85	1,220.80	274.95	29.1%
30	65%	14,235	1,175.50	1,524.47	348.97	29.7%
30	80%	17,520	1,405.15	1,828.13	422.98	30.1%
75	20%	10,950	1,155.15	1,456.24	301.09	26.1%
75	35%	19,163	1,729.32	2,215.45	486.13	28.1%
75	50%	27,375	2,303.42	2,974.57	671.15	29.1%
75	65%	35,588	2,877.59	3,733.78	856.19	29.8%
75	80%	43,800	3,451.69	4,492.90	1,041.21	30.2%
100	20%	14,600	1,526.59	1,924.45	397.86	26.1%
100	35%	25,550	2,292.10	2,936.67	644.57	28.1%
100	50%	36,500	3,057.62	3,948.88	891.26	29.1%
100	65%	47,450	3,823.13	4,961.10	1,137.97	29.8%
100	80%	58,400	4,588.65	5,973.32	1,384.67	30.2%
150	20%	21,900	2,269.48	2,860.86	591.38	26.1%
150	35%	38,325	3,417.75	4,379.19	961.44	28.1%
150	50%	54,750	4,566.02	5,897.51	1,331.49	29.2%
150	65%	71,175	5,714.30	7,415.84	1,701.54	29.8%
150	80%	87,600	6,862.57	8,934.17	2,071.60	30.2%
200	20%	29,200	3,012.37	3,797.27	784.90	26.1%
200	35%	51,100	4,543.40	5,821.71	1,278.31	28.1%
200	50%	73,000	6,074.43	7,846.14	1,771.71	29.2%
200	65%	94,900	7,605.46	9,870.58	2,265.12	29.8%
200	80%	116,800	9,136.49	11,895.02	2,758.53	30.2%
300	20%	43,800	4,498.16	5,670.10	1,171.94	26.1%
300	35%	76,650	6,794.70	8,706.75	1,912.05	28.1%
300	50%	109,500	9,091.25	11,743.40	2,652.15	29.2%
300	65%	142,350	11,387.79	14,780.06	3,392.27	29.8%
300	80%	175,200	13,684.33	17,816.71	4,132.38	30.2%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
E-221-8T time-of-use

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount ($)	%
						(F) - (E)	(G) / (E)
10	30	20%	1,460	301.85	388.16	86.31	28.6%
10	30	35%	2,555	361.29	466.67	105.38	29.2%
10	30	50%	3,650	420.76	545.24	124.48	29.6%
10	30	65%	4,745	480.20	623.76	143.56	29.9%
10	30	80%	5,840	539.62	702.27	162.65	30.1%
30	90	20%	4,380	838.92	1,081.07	242.15	28.9%
30	90	35%	7,665	1,017.26	1,316.67	299.41	29.4%
30	90	50%	10,950	1,195.64	1,552.32	356.68	29.8%
30	90	65%	14,235	1,373.98	1,787.94	413.96	30.1%
30	90	80%	17,520	1,552.32	2,023.54	471.22	30.4%
75	225	20%	10,950	2,047.36	2,640.15	592.79	29.0%
75	225	35%	19,163	2,493.27	3,229.26	735.99	29.5%
75	225	50%	27,375	2,939.14	3,818.29	879.15	29.9%
75	225	65%	35,588	3,385.05	4,407.39	1,022.34	30.2%
75	225	80%	43,800	3,830.92	4,996.42	1,165.50	30.4%
100	300	20%	14,600	2,718.68	3,506.29	787.61	29.0%
100	300	35%	25,550	3,313.21	4,291.72	978.51	29.5%
100	300	50%	36,500	3,907.70	5,077.11	1,169.41	29.9%
100	300	65%	47,450	4,502.23	5,862.55	1,360.32	30.2%
100	300	80%	58,400	5,096.76	6,647.99	1,551.23	30.4%
150	450	20%	21,900	4,061.37	5,238.60	1,177.23	29.0%
150	450	35%	38,325	4,953.15	6,416.73	1,463.58	29.5%
150	450	50%	54,750	5,844.92	7,594.85	1,749.93	29.9%
150	450	65%	71,175	6,736.70	8,772.99	2,036.29	30.2%
150	450	80%	87,600	7,628.48	9,951.12	2,322.64	30.4%
200	600	20%	29,200	5,404.06	6,970.90	1,566.84	29.0%
200	600	35%	51,100	6,593.12	8,541.78	1,948.66	29.6%
200	600	50%	73,000	7,782.14	10,112.61	2,330.47	29.9%
200	600	65%	94,900	8,971.16	11,683.43	2,712.27	30.2%
200	600	80%	116,800	10,160.18	13,254.26	3,094.08	30.5%
300	900	20%	43,800	8,089.49	10,435.57	2,346.08	29.0%
300	900	35%	76,650	9,872.99	12,791.78	2,918.79	29.6%
300	900	50%	109,500	11,656.55	15,148.05	3,491.50	30.0%
300	900	65%	142,350	13,440.09	17,504.31	4,064.22	30.2%
300	900	80%	175,200	15,223.64	19,860.58	4,636.94	30.5%

E-221-8T Average Energy On-Peak %: 21%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Summer Peak (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
101	15%	11,060	2,098.15	2,547.86	449.71	21.4%
101	30%	22,119	2,984.96	3,654.88	669.92	22.4%
101	45%	33,179	3,871.73	4,761.83	890.10	23.0%
101	60%	44,238	4,758.44	5,868.70	1,110.26	23.3%
101	75%	55,298	5,645.32	6,975.79	1,330.47	23.6%
150	15%	16,425	2,854.11	3,456.75	602.64	21.1%
150	30%	32,850	4,171.08	5,100.73	929.65	22.3%
150	45%	49,275	5,488.05	6,744.71	1,256.66	22.9%
150	60%	65,700	6,805.02	8,388.70	1,583.68	23.3%
150	75%	82,125	8,122.00	10,032.67	1,910.67	23.5%
200	15%	21,900	3,625.53	4,384.24	758.71	20.9%
200	30%	43,800	5,381.54	6,576.26	1,194.72	22.2%
200	45%	65,700	7,137.42	8,768.15	1,630.73	22.8%
200	60%	87,600	8,893.43	10,960.17	2,066.74	23.2%
200	75%	109,500	10,649.43	13,152.19	2,502.76	23.5%
300	15%	32,850	5,168.28	6,239.08	1,070.80	20.7%
300	30%	65,700	7,802.22	9,527.05	1,724.83	22.1%
300	45%	98,550	10,436.18	12,815.00	2,378.82	22.8%
300	60%	131,400	13,070.23	16,103.10	3,032.87	23.2%
300	75%	164,250	15,704.19	19,391.06	3,686.87	23.5%
350	15%	38,325	5,939.71	7,166.57	1,226.86	20.7%
350	30%	76,650	9,012.69	11,002.58	1,989.89	22.1%
350	45%	114,975	12,085.67	14,838.57	2,752.90	22.8%
350	60%	153,300	15,158.52	18,674.44	3,515.92	23.2%
350	75%	191,625	18,231.50	22,510.43	4,278.93	23.5%
400	15%	43,800	6,711.14	8,094.06	1,382.92	20.6%
400	30%	87,600	10,223.03	12,477.97	2,254.94	22.1%
400	45%	131,400	13,735.03	16,862.00	3,126.97	22.8%
400	60%	175,200	17,246.94	21,245.91	3,998.97	23.2%
400	75%	219,000	20,758.94	25,629.95	4,871.01	23.5%

GS-SCHOOLS M Average Energy On-Peak %: 11.79%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
101	15%	11,060	1,857.52	2,247.31	389.79	21.0%
101	30%	22,119	2,503.62	3,053.65	550.03	22.0%
101	45%	33,179	3,149.84	3,860.14	710.30	22.6%
101	60%	44,238	3,795.93	4,666.48	870.55	22.9%
101	75%	55,298	4,442.07	5,472.87	1,030.80	23.2%
150	15%	16,425	2,496.70	3,010.32	513.62	20.6%
150	30%	32,850	3,456.33	4,207.96	751.63	21.7%
150	45%	49,275	4,415.90	5,405.52	989.62	22.4%
150	60%	65,700	5,375.53	6,603.16	1,227.63	22.8%
150	75%	82,125	6,335.09	7,800.71	1,465.62	23.1%
200	15%	21,900	3,149.02	3,789.05	640.03	20.3%
200	30%	43,800	4,428.44	5,385.78	957.34	21.6%
200	45%	65,700	5,707.93	6,982.61	1,274.68	22.3%
200	60%	87,600	6,987.42	8,579.43	1,592.01	22.8%
200	75%	109,500	8,266.84	10,176.17	1,909.33	23.1%
300	15%	32,850	4,453.53	5,346.31	892.78	20.0%
300	30%	65,700	6,372.73	7,741.51	1,368.78	21.5%
300	45%	98,550	8,291.93	10,136.70	1,844.77	22.2%
300	60%	131,400	10,211.13	12,531.89	2,320.76	22.7%
300	75%	164,250	12,130.33	14,927.09	2,796.76	23.1%
350	15%	38,325	5,105.78	6,124.95	1,019.17	20.0%
350	30%	76,650	7,344.84	8,919.32	1,574.48	21.4%
350	45%	114,975	9,583.89	11,713.70	2,129.81	22.2%
350	60%	153,300	11,823.02	14,508.18	2,685.16	22.7%
350	75%	191,625	14,062.08	17,302.56	3,240.48	23.0%
400	15%	43,800	5,758.04	6,903.58	1,145.54	19.9%
400	30%	87,600	8,317.02	10,097.23	1,780.21	21.4%
400	45%	131,400	10,875.93	13,290.79	2,414.86	22.2%
400	60%	175,200	13,434.84	16,484.35	3,049.51	22.7%
400	75%	219,000	15,993.83	19,678.02	3,684.19	23.0%

GS-SCHOOLS M Average Energy On-Peak %: 18%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Summer Peak (May - October)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
401	15%	43,910	6,608.83	8,016.49	1,407.66	21.3%
401	30%	87,819	10,023.38	12,309.99	2,286.61	22.8%
401	45%	131,729	13,438.08	16,603.69	3,165.61	23.6%
401	60%	175,638	16,852.71	20,897.32	4,044.61	24.0%
401	75%	219,548	20,267.31	25,190.89	4,923.58	24.3%
600	15%	65,700	9,598.77	11,630.06	2,031.29	21.2%
600	30%	131,400	14,708.00	18,054.50	3,346.50	22.8%
600	45%	197,100	19,817.14	24,478.81	4,661.67	23.5%
600	60%	262,800	24,926.37	30,903.26	5,976.89	24.0%
600	75%	328,500	30,035.52	37,327.58	7,292.06	24.3%
800	15%	87,600	12,603.87	15,261.98	2,658.11	21.1%
800	30%	175,200	19,416.13	23,827.82	4,411.69	22.7%
800	45%	262,800	26,228.37	32,393.66	6,165.29	23.5%
800	60%	350,400	33,040.63	40,959.49	7,918.86	24.0%
800	75%	438,000	39,852.88	49,525.33	9,672.45	24.3%
1,000	15%	109,500	15,608.89	18,893.77	3,284.88	21.0%
1,000	30%	219,000	24,124.26	29,601.14	5,476.88	22.7%
1,000	45%	328,500	32,639.52	40,308.38	7,668.86	23.5%
1,000	60%	438,000	41,154.88	51,015.73	9,860.85	24.0%
1,000	75%	547,500	49,670.15	61,722.98	12,052.83	24.3%
1,500	15%	164,250	23,121.62	27,973.51	4,851.89	21.0%
1,500	30%	328,500	35,894.52	44,034.38	8,139.86	22.7%
1,500	45%	492,750	48,667.52	60,095.35	11,427.83	23.5%
1,500	60%	657,000	61,440.42	76,156.21	14,715.79	24.0%
1,500	75%	821,250	74,213.41	92,217.19	18,003.78	24.3%
3,000	15%	328,500	45,659.52	55,212.38	9,552.86	20.9%
3,000	30%	657,000	71,205.42	87,334.21	16,128.79	22.7%
3,000	45%	985,500	96,751.41	119,456.17	22,704.76	23.5%
3,000	60%	1,314,000	122,297.31	151,578.01	29,280.70	23.9%
3,000	75%	1,642,500	147,843.21	183,699.84	35,856.63	24.3%

GS-SCHOOLS L Average Energy On-Peak %: 13%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Winter (November - April)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
401	15%	43,910	5,717.53	6,894.80	1,177.27	20.6%
401	30%	87,819	8,240.90	10,066.76	1,825.86	22.2%
401	45%	131,729	10,764.31	13,238.76	2,474.45	23.0%
401	60%	175,638	13,287.67	16,410.72	3,123.05	23.5%
401	75%	219,548	15,811.08	19,582.74	3,771.66	23.9%
600	15%	65,700	8,265.26	9,951.85	1,686.59	20.4%
600	30%	131,400	12,040.91	14,697.97	2,657.06	22.1%
600	45%	197,100	15,816.55	19,444.08	3,627.53	22.9%
600	60%	262,800	19,592.19	24,190.20	4,598.01	23.5%
600	75%	328,500	23,367.83	28,936.31	5,568.48	23.8%
800	15%	87,600	10,825.81	13,024.30	2,198.49	20.3%
800	30%	175,200	15,860.00	19,352.44	3,492.44	22.0%
800	45%	262,800	20,894.19	25,680.60	4,786.41	22.9%
800	60%	350,400	25,928.38	32,008.75	6,080.37	23.5%
800	75%	438,000	30,962.58	38,336.91	7,374.33	23.8%
1,000	15%	109,500	13,386.36	16,096.73	2,710.37	20.2%
1,000	30%	219,000	19,679.09	24,006.92	4,327.83	22.0%
1,000	45%	328,500	25,971.83	31,917.11	5,945.28	22.9%
1,000	60%	438,000	32,264.58	39,827.31	7,562.73	23.4%
1,000	75%	547,500	38,557.25	47,737.42	9,180.17	23.8%
1,500	15%	164,250	19,787.73	23,777.83	3,990.10	20.2%
1,500	30%	328,500	29,226.83	35,643.11	6,416.28	22.0%
1,500	45%	492,750	38,665.95	47,508.40	8,842.45	22.9%
1,500	60%	657,000	48,104.98	59,373.61	11,268.63	23.4%
1,500	75%	821,250	57,544.09	71,238.90	13,694.81	23.8%
3,000	15%	328,500	38,991.83	46,821.11	7,829.28	20.1%
3,000	30%	657,000	57,869.98	70,551.61	12,681.63	21.9%
3,000	45%	985,500	76,748.20	94,282.18	17,533.98	22.8%
3,000	60%	1,314,000	95,626.41	118,012.75	22,386.34	23.4%
3,000	75%	1,642,500	114,504.57	141,743.25	27,238.68	23.8%

GS-SCHOOLS L Average Energy On-Peak %: 21%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self-contained
   100 kW and above = Instrument-rated

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
E-47

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
						Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (F) - (E)	% (G) / (E)
HPS, cobra / roadway	5,800	29	Company	9.21	10.64	1.43	15.5%
		29	Customer	5.45	6.30	0.85	15.6%
HPS, cobra / roadway	9,500	41	Company	10.84	12.52	1.68	15.5%
		41	Customer	6.67	7.70	1.03	15.4%
HPS, architectural	9,500	41	Company	16.22	18.74	2.52	15.5%
		41	Customer	7.53	8.70	1.17	15.5%
LED, acorn	3,835	26	Company	21.19	24.48	3.29	15.5%
		26	Customer	2.68	3.10	0.42	15.7%
HPS, cobra / roadway	16,000	69	Company	13.58	15.69	2.11	15.5%
		69	Customer	9.31	10.75	1.44	15.5%
HPS, architectural	16,000	69	Company	18.94	21.88	2.94	15.5%
		69	Customer	10.36	11.97	1.61	15.5%
LED, Cobra	5,300	23	Company	10.24	11.83	1.59	15.5%
		23	Customer	2.44	2.82	0.38	15.6%
HPS, cobra / roadway	30,000	99	Company	16.38	18.92	2.54	15.5%
		99	Customer	12.10	13.98	1.88	15.5%
HPS, architectural	30,000	99	Company	22.48	25.97	3.49	15.5%
		99	Customer	13.29	15.35	2.06	15.5%
HPS, cobra / roadway	50,000	153	Company	22.22	25.67	3.45	15.5%
		153	Customer	17.27	19.95	2.68	15.5%
LED, architectural	4,800	15	Company	8.10	9.36	1.26	15.6%
		15	Customer	1.51	1.74	0.23	15.2%
LPS, architectural	8,000	30	Company	23.59	27.25	3.66	15.5%
		30	Customer	10.36	11.97	1.61	15.5%
LPS, architectural	13,500	50	Company	27.81	32.12	4.31	15.5%
		50	Customer	12.50	14.44	1.94	15.5%
LED, roadway	5,300	24	Company	9.78	11.30	1.52	15.5%
		24	Customer	2.36	2.73	0.37	15.7%
LED, post top	6,400	30	Company	12.49	14.43	1.94	15.5%
		30	Customer	2.90	3.35	0.45	15.5%
Type of Pole	Height	Desc.					
Direct Bury	30 FT	Round Steel	Company	15.17	17.52	2.35	15.5%
			Customer	N/A			
Direct Bury	34 FT	Square Steel	Company	16.74	19.34	2.60	15.5%
			Customer	N/A			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
E-58

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
						Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (F) - (E)	% (G) / (E)
HPS, cobra / roadway	5,800	29	Company	9.21	10.91	1.70	18.5%
		29	Customer	5.45	6.45	1.00	18.3%
HPS, cobra / roadway	9,500	41	Company	10.84	12.84	2.00	18.5%
		41	Customer	6.67	7.89	1.22	18.3%
HPS, architectural	9,500	41	Company	16.22	19.22	3.00	18.5%
		41	Customer	7.74	9.16	1.42	18.3%
FI Post Top Colonial Gray	8,000	38	Company	19.56	23.19	3.63	18.6%
		38	Customer	5.52	6.53	1.01	18.3%
HPS, cobra / roadway	16,000	69	Company	13.58	16.09	2.51	18.5%
		69	Customer	9.31	11.03	1.72	18.5%
HPS, architectural	16,000	69	Company	20.49	24.29	3.80	18.5%
		69	Customer	20.04	23.76	3.72	18.6%
HPS Post Top	9,500	41	Company	11.19	13.26	2.07	18.5%
		41	Customer	7.01	8.30	1.29	18.4%
HPS, cobra / roadway	30,000	99	Company	16.38	19.41	3.03	18.5%
		99	Customer	12.10	14.34	2.24	18.5%
HPS, architectural	30,000	99	Company	22.48	26.65	4.17	18.5%
		99	Customer	13.29	15.75	2.46	18.5%
HPS, cobra / roadway	50,000	153	Company	22.22	26.34	4.12	18.5%
		153	Customer	17.27	20.47	3.20	18.5%
HPS, architectural	50,000	153	Company	27.74	32.89	5.15	18.6%
		153	Customer	19.13	22.68	3.55	18.6%
LPS, architectural	8,000	30	Company	23.59	27.97	4.38	18.6%
LPS, architectural	13,500	50	Company	27.81	32.98	5.17	18.6%
LPS, architectural	22,500	72	Company	31.77	37.67	5.90	18.6%
LED, roadway	4,800	90	Company	7.60	9.00	1.40	18.4%
		90	Customer	3.07	3.62	0.55	17.9%
Type of Pole	Height	Desc.					
Direct Bury	30 FT	Round Steel	Company	15.17	17.98	2.81	18.5%
			Customer	2.81	3.31	0.50	17.8%
Direct Bury	34 FT	Square Steel	Company	16.74	19.84	3.10	18.5%
			Customer	2.90	3.42	0.52	17.9%
Direct Bury	38 FT	Square Steel	Company	17.98	21.31	3.33	18.5%
			Customer	3.12	3.68	0.56	17.9%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
E-59

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
Lamps	kWh per Lamp	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
50	30	1,500	243.44	288.20	44.76	18.4%
50	60	3,000	339.87	402.39	62.52	18.4%
50	75	3,750	388.09	459.49	71.40	18.4%
50	100	5,000	468.45	554.65	86.20	18.4%
50	150	7,500	629.18	744.98	115.80	18.4%
100	30	3,000	486.87	576.39	89.52	18.4%
100	60	6,000	679.74	804.78	125.04	18.4%
100	75	7,500	776.18	918.98	142.80	18.4%
100	100	10,000	936.90	1,109.30	172.40	18.4%
100	150	15,000	1,258.35	1,489.95	231.60	18.4%
200	30	6,000	973.74	1,152.78	179.04	18.4%
200	60	12,000	1,359.48	1,609.56	250.08	18.4%
200	75	15,000	1,552.35	1,837.95	285.60	18.4%
200	100	20,000	1,873.80	2,218.60	344.80	18.4%
200	150	30,000	2,516.70	2,979.90	463.20	18.4%
500	30	15,000	2,434.35	2,881.95	447.60	18.4%
500	60	30,000	3,398.70	4,023.90	625.20	18.4%
500	75	37,500	3,880.88	4,594.88	714.00	18.4%
500	100	50,000	4,684.50	5,546.50	862.00	18.4%
500	150	75,000	6,291.75	7,449.75	1,158.00	18.4%
1,000	30	30,000	4,868.70	5,763.90	895.20	18.4%
1,000	60	60,000	6,797.40	8,047.80	1,250.40	18.4%
1,000	75	75,000	7,761.75	9,189.75	1,428.00	18.4%
1,000	100	100,000	9,369.00	11,093.00	1,724.00	18.4%
1,000	150	150,000	12,583.50	14,899.50	2,316.00	18.4%
2,000	30	60,000	9,737.40	11,527.80	1,790.40	18.4%
2,000	60	120,000	13,594.80	16,095.60	2,500.80	18.4%
2,000	75	150,000	15,523.50	18,379.50	2,856.00	18.4%
2,000	100	200,000	18,738.00	22,186.00	3,448.00	18.4%
2,000	150	300,000	25,167.00	29,799.00	4,632.00	18.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Classified Bill Analysis at Present and Proposed Rates
E-67

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
			(C) - (B)	(D) / (B)
30	1.64	1.95	0.31	18.9%
40	2.19	2.60	0.41	18.7%
50	2.74	3.25	0.51	18.6%
60	3.29	3.90	0.61	18.5%
70	3.84	4.55	0.71	18.5%
80	4.38	5.19	0.81	18.5%
90	4.93	5.84	0.91	18.5%
100	5.48	6.49	1.01	18.4%
125	6.85	8.12	1.27	18.5%
150	8.22	9.74	1.52	18.5%
175	9.59	11.36	1.77	18.5%
200	10.96	12.99	2.03	18.5%
225	12.33	14.61	2.28	18.5%
250	13.70	16.23	2.53	18.5%
275	15.07	17.86	2.79	18.5%
300	16.44	19.48	3.04	18.5%
325	17.81	21.10	3.29	18.5%
350	19.18	22.73	3.55	18.5%
375	20.55	24.35	3.80	18.5%
400	21.92	25.97	4.05	18.5%
425	23.29	27.60	4.31	18.5%
450	24.66	29.22	4.56	18.5%
475	26.03	30.84	4.81	18.5%
500	27.41	32.47	5.06	18.5%
600	32.89	38.96	6.07	18.5%
700	38.37	45.45	7.08	18.5%
800	43.85	51.94	8.09	18.4%
900	49.33	58.44	9.11	18.5%
1,000	54.81	64.93	10.12	18.5%
1,500	82.22	97.40	15.18	18.5%
2,000	109.62	129.86	20.24	18.5%
2,500	137.03	162.33	25.30	18.5%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective as of 12/01/2021.

Note: There may be variances in displayed values due to rounding.

Arizona Public Service Company
Standard Filing Requirement Schedule H-4
Test Year Ended June 30, 2022
Typical Service Bill Analysis

(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) *(E) - (D)*	% *(F) / (D)*

No typical bill analysis is presented for the following Rate Schedules:

E-56

E-36 XL

E-221 AG

E-221 AG TOU

Note: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-12 Solar Legacy**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	101,688	-	101,688	56.42%	-	0.00%	103,324	-	103,324	57.31%	-	0.00%	1
2	1-50	2,804	71,779	104,492	57.97%	71,779	0.11%	6,749	172,360	110,073	61.05%	172,360	0.45%	2
3	51-100	2,745	206,156	107,237	59.50%	277,935	0.41%	6,473	486,198	116,546	64.64%	658,558	1.71%	3
4	101-150	2,803	351,293	110,040	61.05%	629,228	0.92%	6,193	774,556	122,739	68.08%	1,433,114	3.72%	4
5	151-200	2,736	478,126	112,776	62.57%	1,107,354	1.62%	5,739	1,003,044	128,478	71.26%	2,436,158	6.32%	5
6	201-250	2,806	632,714	115,582	64.12%	1,740,068	2.55%	5,283	1,187,424	133,761	74.19%	3,623,582	9.39%	6
7	251-300	2,799	770,117	118,381	65.68%	2,510,185	3.68%	4,682	1,284,530	138,443	76.79%	4,908,112	12.72%	7
8	301-350	2,751	893,381	121,132	67.20%	3,403,566	4.99%	4,163	1,348,964	142,606	79.10%	6,257,076	16.22%	8
9	351-400	2,787	1,043,563	123,919	68.75%	4,447,129	6.52%	3,972	1,485,620	146,578	81.30%	7,742,696	20.07%	9
10	401-450	2,730	1,158,693	126,649	70.26%	5,605,822	8.22%	3,505	1,486,650	150,083	83.24%	9,229,346	23.93%	10
11	451-500	2,722	1,292,302	129,371	71.78%	6,898,124	10.12%	3,047	1,445,685	153,130	84.93%	10,675,031	27.67%	11
12	501-550	2,698	1,413,482	132,069	73.27%	8,311,606	12.19%	2,847	1,491,959	155,977	86.51%	12,166,990	31.54%	12
13	551-600	2,636	1,513,408	134,705	74.73%	9,825,014	14.41%	2,571	1,474,814	158,548	87.94%	13,641,804	35.37%	13
14	601-650	2,685	1,675,816	137,390	76.22%	11,500,830	16.87%	2,273	1,417,671	160,821	89.20%	15,059,475	39.04%	14
15	651-700	2,603	1,754,219	139,993	77.67%	13,255,049	19.44%	1,958	1,318,534	162,779	90.28%	16,378,009	42.46%	15
16	701-750	2,485	1,798,509	142,478	79.05%	15,053,558	22.08%	1,766	1,278,077	164,545	91.26%	17,656,086	45.77%	16
17	751-800	2,425	1,876,030	144,903	80.39%	16,929,588	24.83%	1,620	1,252,448	166,165	92.16%	18,908,534	49.02%	17
18	801-850	2,332	1,919,596	147,235	81.69%	18,849,184	27.65%	1,405	1,156,302	167,570	92.94%	20,064,836	52.02%	18
19	851-900	2,149	1,877,160	149,384	82.88%	20,726,344	30.40%	1,272	1,110,692	168,842	93.65%	21,175,528	54.90%	19
20	901-950	2,172	2,005,619	151,556	84.08%	22,731,963	33.34%	1,096	1,011,064	169,938	94.26%	22,186,592	57.52%	20
21	951-1,000	2,078	2,021,067	153,634	85.24%	24,753,030	36.31%	1,013	985,810	170,951	94.82%	23,172,402	60.07%	21
22	1,001-1,100	3,667	3,836,999	157,301	87.27%	28,590,029	41.94%	1,646	1,723,078	172,597	95.73%	24,895,480	64.54%	22
23	1,101-1,200	3,321	3,810,438	160,622	89.11%	32,400,467	47.52%	1,262	1,445,822	173,859	96.43%	26,341,302	68.29%	23
24	1,201-1,300	2,906	3,622,377	163,528	90.73%	36,022,844	52.84%	1,030	1,285,119	174,889	97.00%	27,626,421	71.62%	24
25	1,301-1,400	2,457	3,310,676	165,985	92.09%	39,333,520	57.69%	859	1,156,460	175,748	97.48%	28,782,881	74.62%	25
26	1,401-1,500	2,235	3,231,769	168,220	93.33%	42,565,289	62.43%	684	988,639	176,432	97.86%	29,771,520	77.18%	26
27	1,501-1,600	1,803	2,788,470	170,023	94.33%	45,353,759	66.52%	566	875,931	176,998	98.17%	30,647,451	79.45%	27
28	1,601-1,700	1,550	2,551,230	171,573	95.19%	47,904,989	70.27%	499	820,581	177,497	98.45%	31,468,032	81.58%	28
29	1,701-1,800	1,419	2,477,222	172,992	95.98%	50,382,211	73.90%	395	690,292	177,892	98.67%	32,158,324	83.37%	29
30	1,801-1,900	1,134	2,091,398	174,126	96.61%	52,473,609	76.97%	349	644,693	178,241	98.86%	32,803,017	85.04%	30
31	1,901-2,000	949	1,847,374	175,075	97.13%	54,320,983	79.68%	273	531,277	178,514	99.01%	33,334,294	86.42%	31
32	2,001-2,250	1,758	3,716,155	176,833	98.11%	58,037,138	85.13%	528	1,116,573	179,042	99.30%	34,450,867	89.31%	32
33	2,251-2,500	1,141	2,689,764	177,974	98.74%	60,726,902	89.07%	335	790,351	179,377	99.49%	35,241,218	91.36%	33
34	2,501-3,000	1,241	3,370,892	179,215	99.43%	64,097,794	94.02%	431	1,167,938	179,808	99.73%	36,409,156	94.39%	34
35	3,001-4,000	746	2,511,857	179,961	99.84%	66,609,651	97.70%	301	1,013,543	180,109	99.90%	37,422,699	97.02%	35
36	4,001-5,000	182	796,551	180,143	99.94%	67,406,202	98.87%	82	360,365	180,191	99.94%	37,783,064	97.95%	36
37	5,001-10,000	80	472,208	180,223	99.99%	67,878,410	99.56%	86	566,674	180,277	99.99%	38,349,738	99.42%	37
38	10,001-20,000	21	275,138	180,244	100.00%	68,153,548	99.97%	19	223,277	180,296	100.00%	38,573,015	100.00%	38
39	over 20,000	1	22,912	180,245	100.00%	68,176,460	100.00%	-	-	180,296	100.00%	38,573,015	100.00%	39

Average Number of Customers:	30,041		Average Number of Customers:	30,049	
Average Consumption:	378	kWh per bill	Average Consumption:	214	kWh per bill
Median Consumption:	-	kWh per bill	Median Consumption:	-	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **ET-1 Solar Legacy**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	19,500	-	19,500	33.88%	-	0.00%	23,681	-	23,681	41.18%	-	0.00%	*1*
2	1-50	670	16,974	20,170	35.04%	16,974	0.04%	2,043	51,962	25,724	44.74%	51,962	0.25%	*2*
3	51-100	681	51,631	20,851	36.22%	68,605	0.14%	1,941	146,359	27,665	48.11%	198,321	0.95%	*3*
4	101-150	740	93,165	21,591	37.51%	161,770	0.33%	2,004	250,847	29,669	51.60%	449,168	2.15%	*4*
5	151-200	773	135,869	22,364	38.85%	297,639	0.62%	1,965	344,598	31,634	55.01%	793,766	3.79%	*5*
6	201-250	742	167,326	23,106	40.14%	464,965	0.96%	1,911	430,527	33,545	58.34%	1,224,293	5.85%	*6*
7	251-300	794	218,818	23,900	41.52%	683,783	1.41%	1,768	486,738	35,313	61.41%	1,711,031	8.17%	*7*
8	301-350	823	268,130	24,723	42.95%	951,913	1.97%	1,706	555,501	37,019	64.38%	2,266,532	10.83%	*8*
9	351-400	841	315,692	25,564	44.41%	1,267,605	2.62%	1,675	628,005	38,694	67.29%	2,894,537	13.83%	*9*
10	401-450	872	370,098	26,436	45.93%	1,637,703	3.38%	1,612	684,396	40,306	70.09%	3,578,933	17.10%	*10*
11	451-500	879	418,051	27,315	47.45%	2,055,754	4.25%	1,437	683,400	41,743	72.59%	4,262,333	20.36%	*11*
12	501-550	883	464,404	28,198	48.99%	2,520,158	5.21%	1,315	689,953	43,058	74.88%	4,952,286	23.66%	*12*
13	551-600	913	525,206	29,111	50.57%	3,045,364	6.29%	1,297	744,775	44,355	77.14%	5,697,061	27.22%	*13*
14	601-650	969	606,989	30,080	52.26%	3,652,353	7.55%	1,189	743,912	45,544	79.20%	6,440,973	30.77%	*14*
15	651-700	939	634,582	31,019	53.89%	4,286,935	8.86%	1,120	757,149	46,664	81.15%	7,198,122	34.39%	*15*
16	701-750	942	683,749	31,961	55.53%	4,970,684	10.27%	984	713,457	47,648	82.86%	7,911,579	37.80%	*16*
17	751-800	979	758,512	32,940	57.23%	5,729,196	11.84%	908	703,968	48,556	84.44%	8,615,547	41.16%	*17*
18	801-850	971	801,492	33,911	58.91%	6,530,688	13.50%	823	679,231	49,379	85.87%	9,294,778	44.40%	*18*
19	851-900	1,020	892,737	34,931	60.69%	7,423,425	15.34%	744	651,325	50,123	87.17%	9,946,103	47.52%	*19*
20	901-950	962	890,327	35,893	62.36%	8,313,752	17.18%	674	623,399	50,797	88.34%	10,569,502	50.49%	*20*
21	951-1,000	899	876,790	36,792	63.92%	9,190,542	18.99%	644	627,443	51,441	89.46%	11,196,945	53.49%	*21*
22	1,001-1,100	1,878	1,969,206	38,670	67.18%	11,159,748	23.06%	1,057	1,108,070	52,498	91.30%	12,305,015	58.79%	*22*
23	1,101-1,200	1,741	2,001,168	40,411	70.21%	13,160,916	27.20%	916	1,053,672	53,414	92.89%	13,358,687	63.82%	*23*
24	1,201-1,300	1,702	2,127,180	42,113	73.16%	15,288,096	31.59%	693	864,624	54,107	94.09%	14,223,311	67.95%	*24*
25	1,301-1,400	1,549	2,092,467	43,662	75.85%	17,380,563	35.92%	579	781,519	54,686	95.10%	15,004,830	71.68%	*25*
26	1,401-1,500	1,491	2,160,879	45,153	78.44%	19,541,442	40.38%	457	661,957	55,143	95.90%	15,666,787	74.85%	*26*
27	1,501-1,600	1,318	2,043,517	46,471	80.73%	21,584,959	44.60%	369	571,226	55,512	96.54%	16,238,013	77.58%	*27*
28	1,601-1,700	1,233	2,033,630	47,704	82.88%	23,618,589	48.81%	344	568,137	55,856	97.14%	16,806,150	80.29%	*28*
29	1,701-1,800	1,145	2,003,010	48,849	84.86%	25,621,599	52.95%	291	509,682	56,147	97.64%	17,315,832	82.72%	*29*
30	1,801-1,900	999	1,849,171	49,848	86.60%	27,470,770	56.77%	178	328,785	56,325	97.95%	17,644,617	84.30%	*30*
31	1,901-2,000	935	1,822,965	50,783	88.22%	29,293,735	60.53%	156	303,281	56,481	98.22%	17,947,898	85.74%	*31*
32	2,001-2,250	1,914	4,052,979	52,697	91.55%	33,346,714	68.91%	301	637,961	56,782	98.75%	18,585,859	88.79%	*32*
33	2,251-2,500	1,342	3,181,847	54,039	93.88%	36,528,561	75.48%	192	455,124	56,974	99.08%	19,040,983	90.97%	*33*
34	2,501-3,000	1,712	4,660,006	55,751	96.86%	41,188,567	85.11%	239	650,509	57,213	99.50%	19,691,492	94.07%	*34*
35	3,001-4,000	1,242	4,203,072	56,993	99.01%	45,391,639	93.80%	177	599,578	57,390	99.80%	20,291,070	96.94%	*35*
36	4,001-5,000	354	1,560,899	57,347	99.63%	46,952,538	97.03%	53	238,728	57,443	99.90%	20,529,798	98.08%	*36*
37	5,001-10,000	202	1,260,349	57,549	99.98%	48,212,887	99.63%	56	350,948	57,499	99.99%	20,880,746	99.76%	*37*
38	10,001-20,000	9	111,883	57,558	99.99%	48,324,770	99.86%	4	51,118	57,503	100.00%	20,931,864	100.00%	*38*
39	over 20,000	3	67,366	57,561	100.00%	48,392,136	100.00%	-	-	57,503	100.00%	20,931,864	100.00%	*39*
		Average Number of Customers:		9,594				Average Number of Customers:		9,584				
		Average Consumption:		841	kWh per bill			Average Consumption:		364	kWh per bill			
		Median Consumption:		582	kWh per bill			Median Consumption:		127	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **ET-2 Solar Legacy**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	59,997	-	59,997	29.01%	-	0.00%	76,839	-	76,839	37.23%	-	0.00%	*1*
2	1-50	2,227	56,277	62,224	30.09%	56,277	0.03%	7,100	182,390	83,939	40.67%	182,390	0.22%	*2*
3	51-100	2,289	173,265	64,513	31.20%	229,542	0.12%	7,130	537,579	91,069	44.13%	719,969	0.86%	*3*
4	101-150	2,387	300,105	66,900	32.35%	529,647	0.27%	7,329	920,334	98,398	47.68%	1,640,303	1.96%	*4*
5	151-200	2,524	444,233	69,424	33.57%	973,880	0.49%	7,106	1,246,123	105,504	51.12%	2,886,426	3.45%	*5*
6	201-250	2,629	592,510	72,053	34.84%	1,566,390	0.79%	6,968	1,569,880	112,472	54.50%	4,456,306	5.33%	*6*
7	251-300	2,720	748,192	74,773	36.16%	2,314,582	1.17%	6,720	1,847,557	119,192	57.75%	6,303,863	7.54%	*7*
8	301-350	2,811	913,288	77,584	37.52%	3,227,870	1.63%	6,546	2,127,347	125,738	60.93%	8,431,210	10.08%	*8*
9	351-400	2,903	1,089,275	80,487	38.92%	4,317,145	2.18%	6,331	2,374,386	132,069	63.99%	10,805,596	12.92%	*9*
10	401-450	2,987	1,269,651	83,474	40.37%	5,586,796	2.82%	6,022	2,560,098	138,091	66.91%	13,365,694	15.98%	*10*
11	451-500	3,118	1,482,038	86,592	41.88%	7,068,834	3.57%	5,586	2,654,139	143,677	69.62%	16,019,833	19.16%	*11*
12	501-550	3,084	1,619,912	89,676	43.37%	8,688,746	4.39%	5,286	2,774,830	148,963	72.18%	18,794,663	22.47%	*12*
13	551-600	3,261	1,876,780	92,937	44.94%	10,565,526	5.34%	4,871	2,800,940	153,834	74.54%	21,595,603	25.82%	*13*
14	601-650	3,367	2,106,053	96,304	46.57%	12,671,579	6.40%	4,491	2,806,973	158,325	76.72%	24,402,576	29.18%	*14*
15	651-700	3,406	2,301,562	99,710	48.22%	14,973,141	7.56%	4,167	2,811,089	162,492	78.74%	27,213,665	32.54%	*15*
16	701-750	3,416	2,477,470	103,126	49.87%	17,450,611	8.81%	3,829	2,776,341	166,321	80.59%	29,990,006	35.86%	*16*
17	751-800	3,594	2,787,693	106,720	51.61%	20,238,304	10.22%	3,547	2,748,782	169,868	82.31%	32,738,788	39.15%	*17*
18	801-850	3,561	2,938,217	110,281	53.33%	23,176,521	11.71%	3,204	2,643,923	173,072	83.86%	35,382,711	42.31%	*18*
19	851-900	3,545	3,103,351	113,826	55.05%	26,279,872	13.27%	2,913	2,548,066	175,985	85.27%	37,930,777	45.36%	*19*
20	901-950	3,469	3,210,494	117,295	56.72%	29,490,366	14.90%	2,786	2,577,872	178,771	86.62%	40,508,649	48.44%	*20*
21	951-1,000	3,692	3,601,593	120,987	58.51%	33,091,959	16.72%	2,504	2,441,403	181,275	87.84%	42,950,052	51.36%	*21*
22	1,001-1,100	7,037	7,390,995	128,024	61.91%	40,482,954	20.45%	4,258	4,465,907	185,533	89.90%	47,415,959	56.70%	*22*
23	1,101-1,200	6,859	7,887,286	134,883	65.23%	48,370,240	24.43%	3,527	4,050,011	189,060	91.61%	51,465,970	61.54%	*23*
24	1,201-1,300	6,401	7,998,575	141,284	68.32%	56,368,815	28.47%	2,833	3,536,807	191,893	92.98%	55,002,777	65.77%	*24*
25	1,301-1,400	6,326	8,538,888	147,610	71.38%	64,907,703	32.79%	2,338	3,153,983	194,231	94.12%	58,156,760	69.54%	*25*
26	1,401-1,500	5,791	8,394,152	153,401	74.18%	73,301,855	37.03%	1,930	2,795,472	196,161	95.05%	60,952,232	72.89%	*26*
27	1,501-1,600	5,374	8,324,660	158,775	76.78%	81,626,515	41.23%	1,671	2,588,865	197,832	95.86%	63,541,097	75.98%	*27*
28	1,601-1,700	5,088	8,394,318	163,863	79.24%	90,020,833	45.47%	1,410	2,324,208	199,242	96.54%	65,865,305	78.76%	*28*
29	1,701-1,800	4,701	8,224,349	168,564	81.52%	98,245,182	49.63%	1,074	1,878,713	200,316	97.06%	67,744,018	81.01%	*29*
30	1,801-1,900	4,268	7,890,490	172,832	83.58%	106,135,672	53.61%	869	1,607,414	201,185	97.48%	69,351,432	82.93%	*30*
31	1,901-2,000	3,922	7,643,834	176,754	85.48%	113,779,506	57.47%	771	1,501,292	201,956	97.86%	70,852,724	84.73%	*31*
32	2,001-2,250	7,980	16,917,380	184,734	89.34%	130,696,886	66.02%	1,287	2,717,600	203,243	98.48%	73,570,324	87.98%	*32*
33	2,251-2,500	6,308	14,944,638	191,042	92.39%	145,641,524	73.57%	907	2,153,892	204,150	98.92%	75,724,216	90.55%	*33*
34	2,501-3,000	7,597	20,685,431	198,639	96.06%	166,326,955	84.02%	999	2,713,249	205,149	99.41%	78,437,465	93.80%	*34*
35	3,001-4,000	5,752	19,490,113	204,391	98.84%	185,817,068	93.86%	739	2,516,260	205,888	99.76%	80,953,725	96.81%	*35*
36	4,001-5,000	1,570	6,895,953	205,961	99.60%	192,713,021	97.35%	271	1,210,691	206,159	99.89%	82,164,416	98.25%	*36*
37	5,001-10,000	783	4,762,647	206,744	99.98%	197,475,668	99.75%	202	1,271,247	206,361	99.99%	83,435,663	99.77%	*37*
38	10,001-20,000	41	490,503	206,785	100.00%	197,966,171	100.00%	15	189,111	206,376	100.00%	83,624,774	100.00%	*38*
39	over 20,000	-	-	206,785	100.00%	197,966,171	100.00%	-	-	206,376	100.00%	83,624,774	100.00%	*39*

Average Number of Customers:	34,464		Average Number of Customers:	34,396	
Average Consumption:	957	kWh per bill	Average Consumption:	405	kWh per bill
Median Consumption:	754	kWh per bill	Median Consumption:	184	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **ECT-1R Solar Legacy**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	314	-	314	24.76%	-	0.00%	392	-	392	31.24%	-	0.00%	1
2	1-50	8	190	322	25.39%	190	0.01%	33	677	425	33.86%	677	0.06%	2
3	51-100	12	933	334	26.34%	1,123	0.05%	28	1,946	453	36.10%	2,623	0.23%	3
4	101-150	7	907	341	26.89%	2,030	0.09%	29	3,618	482	38.41%	6,241	0.55%	4
5	151-200	12	2,069	353	27.84%	4,099	0.19%	26	4,628	508	40.48%	10,869	0.96%	5
6	201-250	11	2,567	364	28.71%	6,666	0.31%	29	6,630	537	42.79%	17,499	1.54%	6
7	251-300	14	3,881	378	29.81%	10,547	0.49%	32	8,738	569	45.34%	26,237	2.32%	7
8	301-350	10	3,221	388	30.60%	13,768	0.64%	34	11,105	603	48.05%	37,342	3.30%	8
9	351-400	8	3,063	396	31.23%	16,831	0.78%	32	11,905	635	50.60%	49,247	4.35%	9
10	401-450	21	9,039	417	32.89%	25,870	1.20%	29	12,273	664	52.91%	61,520	5.43%	10
11	451-500	11	5,256	428	33.75%	31,126	1.45%	37	17,543	701	55.86%	79,063	6.98%	11
12	501-550	7	3,653	435	34.31%	34,779	1.62%	28	14,774	729	58.09%	93,837	8.28%	12
13	551-600	15	8,621	450	35.49%	43,400	2.02%	28	16,037	757	60.32%	109,874	9.70%	13
14	601-650	19	11,837	469	36.99%	55,237	2.57%	31	19,247	788	62.79%	129,121	11.40%	14
15	651-700	22	14,972	491	38.72%	70,209	3.26%	19	12,844	807	64.30%	141,965	12.53%	15
16	701-750	22	15,953	513	40.46%	86,162	4.00%	19	13,706	826	65.82%	155,671	13.74%	16
17	751-800	17	13,138	530	41.80%	99,300	4.61%	22	16,961	848	67.57%	172,632	15.24%	17
18	801-850	10	8,234	540	42.59%	107,534	5.00%	27	22,227	875	69.72%	194,859	17.20%	18
19	851-900	15	13,221	555	43.77%	120,755	5.61%	15	13,106	890	70.92%	207,965	18.36%	19
20	901-950	15	13,816	570	44.95%	134,571	6.25%	17	15,662	907	72.27%	223,627	19.74%	20
21	951-1,000	17	16,609	587	46.29%	151,180	7.02%	21	20,508	928	73.94%	244,135	21.55%	21
22	1,001-1,100	39	40,935	626	49.37%	192,115	8.93%	21	21,972	949	75.62%	266,107	23.49%	22
23	1,101-1,200	38	43,636	664	52.37%	235,751	10.95%	33	37,791	982	78.25%	303,898	26.83%	23
24	1,201-1,300	29	36,369	693	54.65%	272,120	12.64%	28	35,104	1,010	80.48%	339,002	29.93%	24
25	1,301-1,400	25	33,750	718	56.62%	305,870	14.21%	26	35,158	1,036	82.55%	374,160	33.03%	25
26	1,401-1,500	37	53,890	755	59.54%	359,760	16.72%	12	17,422	1,048	83.51%	391,582	34.57%	26
27	1,501-1,600	28	43,714	783	61.75%	403,474	18.75%	19	29,435	1,067	85.02%	421,017	37.17%	27
28	1,601-1,700	23	38,155	806	63.56%	441,629	20.52%	14	23,239	1,081	86.14%	444,256	39.22%	28
29	1,701-1,800	23	40,053	829	65.38%	481,682	22.38%	10	17,440	1,091	86.93%	461,696	40.76%	29
30	1,801-1,900	34	62,977	863	68.06%	544,659	25.31%	13	23,925	1,104	87.97%	485,621	42.87%	30
31	1,901-2,000	34	66,038	897	70.74%	610,697	28.38%	7	13,658	1,111	88.53%	499,279	44.08%	31
32	2,001-2,250	65	138,710	962	75.87%	749,407	34.82%	26	54,969	1,137	90.60%	554,248	48.93%	32
33	2,251-2,500	44	104,510	1,006	79.34%	853,917	39.68%	25	59,725	1,162	92.59%	613,973	54.20%	33
34	2,501-3,000	75	206,426	1,081	85.25%	1,060,343	49.27%	36	98,308	1,198	95.46%	712,281	62.88%	34
35	3,001-4,000	92	313,518	1,173	92.51%	1,373,861	63.84%	20	66,899	1,218	97.05%	779,180	68.79%	35
36	4,001-5,000	33	145,251	1,206	95.11%	1,519,112	70.58%	6	26,826	1,224	97.53%	806,006	71.16%	36
37	5,001-10,000	45	308,094	1,251	98.66%	1,827,206	84.90%	19	131,053	1,243	99.04%	937,059	82.73%	37
38	10,001-20,000	10	147,962	1,261	99.45%	1,975,168	91.77%	11	173,158	1,254	99.92%	1,110,217	98.02%	38
39	over 20,000	7	177,036	1,268	100.00%	2,152,204	100.00%	1	22,474	1,255	100.00%	1,132,691	100.00%	39
	Average Number of Customers:			211				Average Number of Customers:		209				
	Average Consumption:			1,697	kWh per bill			Average Consumption:		903	kWh per bill			
	Median Consumption:			1,118	kWh per bill			Median Consumption:		384	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
B LL NG ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **ECT-1R Solar Legacy**
DESCRIPTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW) *(A)*	NUMBER OF BILLS BY BLOCK *(B)*	LOAD kW BY BLOCK *(C)*	Number *(D)*	% of Total *(E)*	Amount (kW) *(F)*	% of Total *(G)*	NUMBER OF B LLS BY BLOCK *(H)*	kW BY BLOCK *(I)*	Number *(J)*	% of Total *(K)*	Amount (kW) *(L)*	% of Total *(M)*	*Line No.*
1	0	4	-	4	0.32%	-	0.00%	3	-	3	0.24%	-	0.00%	*1*
2	0-0.4	3	1	7	0.55%	1	0.01%	3	1	6	0.48%	1	0.01%	*2*
3	0.4-0 8	1	1	8	0.63%	1	0.01%	9	6	15	1.20%	6	0.09%	*3*
4	0 8-1 2	2	2	10	0.79%	3	0.03%	12	13	27	2.15%	19	0.26%	*4*
5	1 2-1 6	6	9	16	1.26%	12	0.12%	33	47	60	4.78%	66	0.92%	*5*
6	1 6-2 0	9	17	25	1.97%	30	0.28%	50	94	110	8.76%	160	2.22%	*6*
7	2 0-2.4	9	19	34	2.68%	49	0.46%	75	168	185	14.74%	328	4.54%	*7*
8	2.4-2 8	16	42	50	3.94%	91	0.85%	64	171	249	19.84%	499	6.90%	*8*
9	2 8-3 2	24	73	74	5.84%	164	1.52%	65	198	314	25.02%	697	9.64%	*9*
10	3 2-3 6	30	104	104	8.20%	267	2.49%	79	272	393	31.31%	969	13.40%	*10*
11	3 6-4 0	31	119	135	10.65%	386	3.60%	105	405	498	39.68%	1,374	19.01%	*11*
12	4 0-4.4	39	166	174	13.72%	552	5.15%	79	335	577	45.98%	1,709	23.64%	*12*
13	4.4-4 8	67	311	241	19.01%	863	8.04%	91	423	668	53.23%	2,131	29.48%	*13*
14	4 8-5 2	68	344	309	24.37%	1,207	11.25%	84	423	752	59.92%	2,555	35.34%	*14*
15	5 2-5 6	75	408	384	30.28%	1,615	15.06%	68	370	820	65.34%	2,924	40.45%	*15*
16	5 6-6 0	67	393	451	35.57%	2,009	18.73%	69	402	889	70.84%	3,327	46.02%	*16*
17	6 0-6.4	76	474	527	41.56%	2,483	23.14%	64	400	953	75.94%	3,727	51.55%	*17*
18	6.4-6 8	67	447	594	46.85%	2,929	27.31%	24	160	977	77.85%	3,886	53.75%	*18*
19	6 8-7 2	50	352	644	50.79%	3,282	30.60%	33	232	1,010	80.48%	4,118	56.96%	*19*
20	7 2-7 6	55	409	699	55.13%	3,691	34.41%	31	230	1,041	82.95%	4,348	60.14%	*20*
21	7 6-8 0	59	463	758	59.78%	4,154	38.72%	25	197	1,066	84.94%	4,545	62.87%	*21*
22	8 0-8.4	62	512	820	64.67%	4,665	43.49%	21	174	1,087	86.61%	4,719	65.27%	*22*
23	8.4-8 8	56	486	876	69.09%	5,151	48.02%	19	164	1,106	88.13%	4,883	67.55%	*23*
24	8 8-9 2	37	334	913	72.00%	5,485	51.14%	15	136	1,121	89.32%	5,019	69.42%	*24*
25	9 2-9 6	39	371	952	75.08%	5,856	54.59%	11	104	1,132	90.20%	5,123	70.86%	*25*
26	9.6-10.0	40	395	992	78.23%	6,251	58.27%	11	109	1,143	91.08%	5,231	72.36%	*26*
27	10 0-10.4	23	237	1,015	80.05%	6,487	60.48%	17	175	1,160	92.43%	5,406	74.77%	*27*
28	10.4-10.8	22	235	1,037	81.78%	6,722	62.67%	9	96	1,169	93.15%	5,501	76.10%	*28*
29	10 8-11.2	22	244	1,059	83.52%	6,965	64.94%	9	101	1,178	93.86%	5,602	77.49%	*29*
30	11 2-12.0	43	501	1,102	86.91%	7,467	69.61%	4	47	1,182	94.18%	5,649	78.14%	*30*
31	12.0 - 13 0	27	339	1,129	89.04%	7,806	72.77%	17	214	1,199	95.54%	5,863	81.10%	*31*
32	13.0 - 14 0	21	285	1,150	90.69%	8,091	75.43%	8	109	1,207	96.18%	5,972	82.61%	*32*
33	14.0 - 15 0	21	306	1,171	92.35%	8,396	78.28%	5	72	1,212	96.57%	6,044	83.61%	*33*
34	15.0 - 16 0	17	265	1,188	93.69%	8,661	80.74%	6	92	1,218	97.05%	6,136	84.88%	*34*
35	16.0 - 17 0	12	199	1,200	94.64%	8,860	82.60%	3	50	1,221	97.29%	6,186	85.57%	*35*
36	17.0 - 18 0	9	158	1,209	95.35%	9,018	84.07%	3	52	1,224	97.53%	6,239	86.30%	*36*
37	18.0 - 19 0	10	187	1,219	96.14%	9,204	85.81%	2	37	1,226	97.69%	6,275	86.81%	*37*
38	19.0 - 20 0	7	135	1,226	96.69%	9,339	87.07%	1	19	1,227	97.77%	6,295	87.07%	*38*
39	20.0 - 25 0	20	446	1,246	98.26%	9,786	91.23%	10	218	1,237	98.57%	6,512	90.08%	*39*
40	25.0 - 30 0	8	214	1,254	98.90%	9,999	93.22%	5	134	1,242	98.96%	6,647	91.94%	*40*
41	Over 30 0	14	727	1,268	100.00%	10,726	100.00%	13	583	1,255	100.00%	7,229	100.00%	*41*
	Average Number of Customers:			211				Average Number of Customers:		209				
	Average Load:			8.5	kW per bill			Average Load:		5 8	kW per bill			
	Median Load:			7.2	kW per bill			Median Load:		4.7	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **ECT-2 Solar Legacy**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	1,783	-	1,783	23.15%	-	0.00%	2,202	-	2,202	28.62%	-	0.00%	1
2	1-50	46	1,292	1,829	23.75%	1,292	0.01%	164	4,451	2,366	30.75%	4,451	0.07%	2
3	51-100	61	4,614	1,890	24.54%	5,906	0.05%	198	15,214	2,564	33.32%	19,665	0.32%	3
4	101-150	60	7,779	1,950	25.32%	13,685	0.11%	186	23,544	2,750	35.74%	43,209	0.71%	4
5	151-200	56	9,923	2,006	26.05%	23,608	0.20%	200	35,910	2,950	38.34%	79,119	1.29%	5
6	201-250	71	16,324	2,077	26.97%	39,932	0.34%	195	44,626	3,145	40.88%	123,745	2.02%	6
7	251-300	61	16,879	2,138	27.76%	56,811	0.48%	194	54,316	3,339	43.40%	178,061	2.91%	7
8	301-350	48	15,936	2,186	28.38%	72,747	0.61%	203	66,658	3,542	46.04%	244,719	4.00%	8
9	351-400	68	25,810	2,254	29.27%	98,557	0.83%	195	74,197	3,737	48.57%	318,916	5.21%	9
10	401-450	86	37,273	2,340	30.38%	135,830	1.14%	176	76,075	3,913	50.86%	394,991	6.46%	10
11	451-500	75	36,281	2,415	31.36%	172,111	1.45%	198	95,710	4,111	53.43%	490,701	8.02%	11
12	501-550	75	39,965	2,490	32.33%	212,076	1.78%	175	92,979	4,286	55.71%	583,680	9.54%	12
13	551-600	89	52,163	2,579	33.48%	264,239	2.22%	170	99,169	4,456	57.92%	682,849	11.16%	13
14	601-650	83	52,575	2,662	34.56%	316,814	2.66%	167	106,243	4,623	60.09%	789,092	12.90%	14
15	651-700	91	62,288	2,753	35.74%	379,102	3.18%	166	113,710	4,789	62.24%	902,802	14.76%	15
16	701-750	84	61,938	2,837	36.83%	441,040	3.71%	164	120,513	4,953	64.37%	1,023,315	16.73%	16
17	751-800	96	75,264	2,933	38.08%	516,304	4.34%	153	120,190	5,106	66.36%	1,143,505	18.70%	17
18	801-850	101	84,435	3,034	39.39%	600,739	5.05%	160	133,930	5,266	68.44%	1,277,435	20.89%	18
19	851-900	91	80,798	3,125	40.57%	681,537	5.73%	155	137,790	5,421	70.46%	1,415,225	23.14%	19
20	901-950	112	105,082	3,237	42.03%	786,619	6.61%	133	124,837	5,554	72.19%	1,540,062	25.18%	20
21	951-1,000	112	110,757	3,349	43.48%	897,376	7.54%	133	131,402	5,687	73.91%	1,671,464	27.33%	21
22	1,001-1,100	222	236,474	3,571	46.36%	1,133,850	9.53%	217	231,095	5,904	76.74%	1,902,559	31.11%	22
23	1,101-1,200	211	246,127	3,782	49.10%	1,379,977	11.59%	215	250,373	6,119	79.53%	2,152,932	35.20%	23
24	1,201-1,300	237	300,607	4,019	52.18%	1,680,584	14.12%	198	251,111	6,317	82.10%	2,404,043	39.31%	24
25	1,301-1,400	206	281,760	4,225	54.86%	1,962,344	16.49%	163	223,436	6,480	84.22%	2,627,479	42.96%	25
26	1,401-1,500	222	326,339	4,447	57.74%	2,288,683	19.23%	133	195,570	6,613	85.95%	2,823,049	46.16%	26
27	1,501-1,600	217	341,478	4,664	60.56%	2,630,161	22.10%	121	190,017	6,734	87.52%	3,013,066	49.26%	27
28	1,601-1,700	232	388,987	4,896	63.57%	3,019,148	25.36%	93	155,198	6,827	88.73%	3,168,264	51.80%	28
29	1,701-1,800	186	330,913	5,082	65.98%	3,350,061	28.14%	101	179,386	6,928	90.04%	3,347,650	54.73%	29
30	1,801-1,900	208	390,378	5,290	68.68%	3,740,439	31.42%	75	140,163	7,003	91.02%	3,487,813	57.03%	30
31	1,901-2,000	167	329,928	5,457	70.85%	4,070,367	34.20%	90	177,502	7,093	92.19%	3,665,315	59.93%	31
32	2,001-2,250	397	855,779	5,854	76.01%	4,926,146	41.38%	125	267,488	7,218	93.81%	3,932,803	64.30%	32
33	2,251-2,500	345	829,853	6,199	80.49%	5,755,999	48.36%	77	184,539	7,295	94.81%	4,117,342	67.32%	33
34	2,501-3,000	564	1,559,868	6,763	87.81%	7,315,867	61.46%	122	338,870	7,417	96.40%	4,456,212	72.86%	34
35	3,001-4,000	519	1,805,801	7,282	94.55%	9,121,668	76.63%	121	419,361	7,538	97.97%	4,875,573	79.72%	35
36	4,001-5,000	195	874,776	7,477	97.08%	9,996,444	83.98%	50	225,538	7,588	98.62%	5,101,111	83.40%	36
37	5,001-10,000	186	1,226,206	7,663	99.49%	11,222,650	94.28%	81	564,663	7,669	99.68%	5,665,774	92.64%	37
38	10,001-20,000	24	289,715	7,687	99.81%	11,512,365	96.72%	16	240,085	7,685	99.88%	5,905,859	96.56%	38
39	over 20,000	15	390,910	7,702	100.00%	11,903,275	100.00%	9	210,308	7,694	100.00%	6,116,167	100.00%	39
	Average Number of Customers:			1,284				Average Number of Customers:		1,282				
	Average Consumption:			1,545	kWh per bill			Average Consumption:		795	kWh per bill			
	Median Consumption:			1,230	kWh per bill			Median Consumption:		435	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
B LL NG ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **ECT-2 Solar Legacy**
DESCRIPTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF B LLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	32	-	32	0.42%	-	0.00%	52	-	52	0.68%	-	0.00%	*1*
2	0-0.4	32	8	64	0.83%	8	0.01%	63	14	115	1.49%	14	0.04%	*2*
3	0.4-0 8	37	25	101	1.31%	33	0.06%	99	66	214	2.78%	80	0.21%	*3*
4	0 8-1 2	32	34	133	1.73%	67	0.12%	189	202	403	5.24%	282	0.72%	*4*
5	1 2-1 6	58	84	191	2.48%	151	0.26%	245	356	648	8.42%	638	1.64%	*5*
6	1 6-2 0	56	102	247	3.21%	253	0.44%	352	648	1,000	13.00%	1,286	3.30%	*6*
7	2 0-2.4	84	190	331	4.30%	443	0.76%	376	839	1,376	17.88%	2,125	5.46%	*7*
8	2.4-2 8	127	340	458	5.95%	783	1.35%	466	1,237	1,842	23.94%	3,361	8.64%	*8*
9	2 8-3 2	174	531	632	8.21%	1,314	2.26%	540	1,650	2,382	30.96%	5,011	12.88%	*9*
10	3 2-3 6	233	805	865	11.23%	2,119	3.65%	544	1,868	2,926	38.03%	6,879	17.68%	*10*
11	3 6-4 0	274	1,057	1,139	14.79%	3,176	5.47%	510	1,947	3,436	44.66%	8,826	22.68%	*11*
12	4 0-4.4	302	1,286	1,441	18.71%	4,462	7.69%	509	2,163	3,945	51.27%	10,989	28.24%	*12*
13	4.4-4 8	342	1,593	1,783	23.15%	6,054	10.43%	512	2,380	4,457	57.93%	13,368	34.35%	*13*
14	4 8-5 2	393	1,987	2,176	28.25%	8,041	13.85%	439	2,192	4,896	63.63%	15,560	39.98%	*14*
15	5 2-5 6	422	2,306	2,598	33.73%	10,346	17.83%	399	2,172	5,295	68.82%	17,732	45.56%	*15*
16	5 6-6 0	442	2,587	3,040	39.47%	12,934	22.29%	349	2,039	5,644	73.36%	19,772	50.80%	*16*
17	6.0-6.4	430	2,691	3,470	45.05%	15,625	26.92%	305	1,905	5,949	77.32%	21,677	55.70%	*17*
18	6.4-6 8	417	2,771	3,887	50.47%	18,396	31.70%	267	1,777	6,216	80.79%	23,453	60.26%	*18*
19	6 8-7 2	397	2,800	4,284	55.62%	21,196	36.52%	227	1,604	6,443	83.74%	25,057	64.39%	*19*
20	7 2-7 6	355	2,641	4,639	60.23%	23,838	41.07%	178	1,326	6,621	86.05%	26,382	67.79%	*20*
21	7 6-8 0	325	2,548	4,964	64.45%	26,386	45.46%	148	1,161	6,769	87.98%	27,543	70.77%	*21*
22	8 0-8.4	337	2,780	5,301	68.83%	29,166	50.26%	143	1,183	6,912	89.84%	28,726	73.81%	*22*
23	8.4-8 8	321	2,774	5,622	72.99%	31,940	55.03%	111	957	7,023	91.28%	29,683	76.27%	*23*
24	8.8-9 2	252	2,281	5,874	76.27%	34,222	58.97%	95	861	7,118	92.51%	30,544	78.48%	*24*
25	9.2-9 6	236	2,230	6,110	79.33%	36,452	62.81%	69	651	7,187	93.41%	31,195	80.16%	*25*
26	9.6-10.0	212	2,084	6,322	82.08%	38,536	66.40%	57	562	7,244	94.15%	31,757	81.60%	*26*
27	10.0-10.4	200	2,048	6,522	84.68%	40,584	69.93%	51	524	7,295	94.81%	32,281	82.95%	*27*
28	10.4-10.8	157	1,673	6,679	86.72%	42,257	72.81%	41	437	7,336	95.35%	32,718	84.07%	*28*
29	10 8-11.2	126	1,391	6,805	88.35%	43,648	75.21%	30	332	7,366	95.74%	33,050	84.92%	*29*
30	11 2-12.0	192	2,236	6,997	90.85%	45,884	79.06%	57	666	7,423	96.48%	33,716	86.63%	*30*
31	12.0 - 13 0	184	2,307	7,181	93.24%	48,191	83.04%	40	504	7,463	97.00%	34,220	87.93%	*31*
32	13.0 - 14 0	119	1,610	7,300	94.78%	49,800	85.81%	38	515	7,501	97.49%	34,735	89.25%	*32*
33	14.0 - 15 0	83	1,200	7,383	95.86%	51,000	87.88%	37	537	7,538	97.97%	35,272	90.63%	*33*
34	15 0 - 16.0	77	1,198	7,460	96.86%	52,198	89.94%	26	406	7,564	98.31%	35,677	91.67%	*34*
35	16 0 - 17.0	42	691	7,502	97.40%	52,889	91.13%	22	368	7,586	98.60%	36,045	92.62%	*35*
36	17.0 - 18 0	30	528	7,532	97.79%	53,416	92.04%	14	249	7,600	98.78%	36,294	93.26%	*36*
37	18.0 - 19 0	29	537	7,561	98.17%	53,953	92.96%	17	314	7,617	99.00%	36,608	94.07%	*37*
38	19.0 - 20 0	22	431	7,583	98.45%	54,383	93.71%	14	271	7,631	99.18%	36,879	94.76%	*38*
39	20.0 - 25 0	66	1,485	7,649	99.31%	55,868	96.26%	34	755	7,665	99.62%	37,634	96.70%	*39*
40	25.0 - 30 0	24	653	7,673	99.62%	56,522	97.39%	4	106	7,669	99.68%	37,740	96.98%	*40*
41	Over 30.0	29	1,515	7,702	100.00%	58,036	100.00%	25	1,177	7,694	100.00%	38,917	100.00%	*41*
		Average Number of Customers:		1,284				Average Number of Customers:		1,282				
		Average Load:		7.5	kW per bill			Average Load:		5.1	kW per bill			
		Median Load:		6.8	kW per bill			Median Load:		4.4	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Fixed-Energy-Charge Plan Tier 1, Fixed-Energy-Charge Plan Tier 1 w/RCP, Fixed-Energy-Charge Plan Tier 1 w/E-3, Fixed-Energy-Charge Plan Tier 1 w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	63,380	-	63,380	3.11%	-	0.00%	45,031	-	45,031	2.16%	-	0.00%	*1*
2	1-50	88,113	2,117,068	151,493	7.42%	2,117,068	0.18%	112,709	2,827,133	157,740	7.55%	2,827,133	0.33%	*2*
3	51-100	93,741	7,158,192	245,234	12.02%	9,275,260	0.77%	120,943	9,177,249	278,683	13.34%	12,004,382	1.39%	*3*
4	101-150	99,879	12,521,105	345,113	16.91%	21,796,365	1.80%	129,999	16,367,791	408,682	19.56%	28,372,173	3.28%	*4*
5	151-200	98,685	17,329,251	443,798	21.74%	39,125,616	3.23%	147,415	25,972,602	556,097	26.62%	54,344,775	6.29%	*5*
6	201-250	101,777	22,974,911	545,575	26.73%	62,100,527	5.13%	166,948	37,713,543	723,045	34.61%	92,058,318	10.65%	*6*
7	251-300	105,534	29,092,017	651,109	31.90%	91,192,544	7.54%	175,508	48,377,508	898,553	43.01%	140,435,826	16.25%	*7*
8	301-350	107,323	34,945,971	758,432	37.16%	126,138,515	10.43%	170,514	55,473,797	1,069,067	51.17%	195,909,623	22.66%	*8*
9	351-400	106,217	39,891,261	864,649	42.36%	166,029,776	13.72%	157,420	59,057,313	1,226,487	58.71%	254,966,936	29.50%	*9*
10	401-450	102,545	43,625,557	967,194	47.39%	209,655,333	17.33%	138,453	58,844,895	1,364,940	65.34%	313,811,831	36.30%	*10*
11	451-500	96,976	46,098,472	1,064,170	52.14%	255,753,805	21.14%	118,861	56,445,664	1,483,801	71.03%	370,257,495	42.83%	*11*
12	501-550	90,422	47,499,449	1,154,592	56.57%	303,253,254	25.07%	99,712	52,340,266	1,583,513	75.80%	422,597,761	48.89%	*12*
13	551-600	84,458	48,598,158	1,239,050	60.71%	351,851,412	29.09%	83,191	47,820,060	1,666,704	79.78%	470,417,821	54.42%	*13*
14	601-650	78,173	48,893,871	1,317,223	64.54%	400,745,283	33.13%	68,488	42,796,085	1,735,192	83.06%	513,213,906	59.37%	*14*
15	651-700	72,533	48,984,770	1,389,756	68.09%	449,730,053	37.18%	56,700	38,266,922	1,791,892	85.77%	551,480,828	63.80%	*15*
16	701-750	66,542	48,260,443	1,456,298	71.35%	497,990,496	41.17%	46,817	33,938,894	1,838,709	88.01%	585,419,722	67.72%	*16*
17	751-800	61,209	47,465,014	1,517,507	74.35%	545,455,510	45.09%	38,741	30,021,739	1,877,450	89.87%	615,441,461	71.20%	*17*
18	801-850	55,294	45,635,297	1,572,801	77.06%	591,090,807	48.86%	32,320	26,663,306	1,909,770	91.42%	642,104,767	74.28%	*18*
19	851-900	50,026	43,790,546	1,622,827	79.51%	634,881,353	52.48%	26,736	23,393,547	1,936,506	92.70%	665,498,314	76.99%	*19*
20	901-950	45,187	41,815,869	1,668,014	81.72%	676,697,222	55.94%	22,221	20,555,267	1,958,727	93.76%	686,053,581	79.36%	*20*
21	951-1,000	40,878	39,873,450	1,708,892	83.73%	716,570,672	59.23%	18,296	17,838,345	1,977,023	94.63%	703,891,926	81.43%	*21*
22	1,001-1,100	67,949	71,264,854	1,776,841	87.06%	787,835,526	65.12%	28,728	30,102,530	2,005,751	96.01%	733,994,456	84.91%	*22*
23	1,101-1,200	53,754	61,743,155	1,830,595	89.69%	849,578,681	70.23%	20,322	23,325,679	2,026,073	96.98%	757,320,135	87.61%	*23*
24	1,201-1,300	42,502	53,079,630	1,873,097	91.77%	902,658,311	74.62%	14,741	18,400,670	2,040,814	97.69%	775,720,805	89.74%	*24*
25	1,301-1,400	32,963	44,465,017	1,906,060	93.39%	947,123,328	78.29%	10,644	14,352,535	2,051,458	98.20%	790,073,340	91.40%	*25*
26	1,401-1,500	26,095	37,812,560	1,932,155	94.67%	984,935,888	81.42%	8,017	11,610,402	2,059,475	98.58%	801,683,742	92.74%	*26*
27	1,501-1,600	20,558	31,843,177	1,952,713	95.67%	1,016,779,065	84.05%	5,906	9,147,320	2,065,381	98.86%	810,831,062	93.80%	*27*
28	1,601-1,700	16,384	27,026,017	1,969,097	96.48%	1,043,805,082	86.28%	4,413	7,276,358	2,069,794	99.08%	818,107,420	94.64%	*28*
29	1,701-1,800	13,031	22,796,061	1,982,128	97.11%	1,066,601,143	88.17%	3,495	6,112,519	2,073,289	99.24%	824,219,939	95.35%	*29*
30	1,801-1,900	10,308	19,065,513	1,992,436	97.62%	1,085,666,656	89.74%	2,707	5,006,470	2,075,996	99.37%	829,226,409	95.93%	*30*
31	1,901-2,000	8,335	16,245,714	2,000,771	98.03%	1,101,912,370	91.09%	2,185	4,258,812	2,078,181	99.48%	833,485,221	96.42%	*31*
32	2,001-2,250	14,682	31,064,030	2,015,453	98.75%	1,132,976,400	93.66%	3,771	7,966,969	2,081,952	99.66%	841,452,190	97.34%	*32*
33	2,251-2,500	8,980	21,250,235	2,024,433	99.19%	1,154,226,635	95.41%	2,204	5,212,522	2,084,156	99.76%	846,664,712	97.94%	*33*
34	2,501-3,000	8,788	23,840,209	2,033,221	99.62%	1,178,066,844	97.38%	2,440	6,633,132	2,086,596	99.88%	853,297,844	98.71%	*34*
35	3,001-4,000	5,477	18,499,733	2,038,698	99.89%	1,196,566,577	98.91%	1,595	5,413,837	2,088,191	99.96%	858,711,681	99.34%	*35*
36	4,001-5,000	1,310	5,768,941	2,040,008	99.95%	1,202,335,518	99.39%	503	2,221,739	2,088,694	99.98%	860,933,420	99.60%	*36*
37	5,001-10,000	950	5,996,171	2,040,958	100.00%	1,208,331,689	99.88%	378	2,424,820	2,089,072	100.00%	863,358,240	99.88%	*37*
38	10,001-20,000	65	850,757	2,041,023	100.00%	1,209,182,446	99.95%	28	355,855	2,089,100	100.00%	863,714,095	99.92%	*38*
39	over 20,000	13	548,606	2,041,036	100.00%	1,209,731,052	100.00%	15	716,346	2,089,115	100.00%	864,430,441	100.00%	*39*
		Average Number of Customers:		340,173				Average Number of Customers:		348,186				
		Average Consumption:		593	kWh per bill			Average Consumption:		414	kWh per bill			
		Median Consumption:		478	kWh per bill			Median Consumption:		343	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Fixed-Energy-Charge Plan Tier 2, Fixed-Energy-Charge Plan Tier 2 w/RCP, Fixed-Energy-Charge Plan Tier 2 w/E-3, Fixed-Energy-Charge Plan Tier 2 w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	886	-	886	0.17%	-	0.00%	797	-	797	0.16%	-	0.00%	*1*
2	1-50	2,165	52,697	3,051	0.58%	52,697	0.01%	3,364	84,013	4,161	0.83%	84,013	0.03%	*2*
3	51-100	2,213	168,641	5,264	1.01%	221,338	0.04%	3,566	270,498	7,727	1.54%	354,511	0.11%	*3*
4	101-150	2,628	332,010	7,892	1.51%	553,348	0.10%	4,209	532,651	11,936	2.38%	887,162	0.28%	*4*
5	151-200	2,895	509,176	10,787	2.06%	1,062,524	0.20%	6,548	1,164,543	18,484	3.68%	2,051,705	0.66%	*5*
6	201-250	3,574	808,985	14,361	2.75%	1,871,509	0.35%	11,703	2,670,450	30,187	6.01%	4,722,155	1.51%	*6*
7	251-300	4,719	1,306,276	19,080	3.65%	3,177,785	0.59%	19,886	5,512,042	50,073	9.97%	10,234,197	3.28%	*7*
8	301-350	6,499	2,123,164	25,579	4.89%	5,300,949	0.99%	28,701	9,379,453	78,774	15.68%	19,613,650	6.28%	*8*
9	351-400	9,157	3,450,738	34,736	6.64%	8,751,687	1.64%	35,822	13,472,621	114,596	22.81%	33,086,271	10.60%	*9*
10	401-450	12,156	5,186,944	46,892	8.97%	13,938,631	2.61%	40,897	17,417,329	155,493	30.96%	50,503,600	16.18%	*10*
11	451-500	15,280	7,277,435	62,172	11.89%	21,216,066	3.97%	42,700	20,303,286	198,193	39.46%	70,806,886	22.68%	*11*
12	501-550	18,018	9,478,637	80,190	15.33%	30,694,703	5.74%	42,389	22,265,654	240,582	47.90%	93,072,540	29.81%	*12*
13	551-600	20,338	11,712,292	100,528	19.22%	42,406,995	7.94%	39,839	22,916,762	280,421	55.83%	115,989,302	37.15%	*13*
14	601-650	21,278	13,311,706	121,806	23.29%	55,718,701	10.43%	35,967	22,470,427	316,388	62.99%	138,459,729	44.35%	*14*
15	651-700	22,172	14,975,718	143,978	27.53%	70,694,419	13.23%	31,115	21,000,349	347,503	69.18%	159,460,078	51.08%	*15*
16	701-750	22,355	16,218,122	166,333	31.80%	86,912,541	16.26%	26,373	19,110,761	373,876	74.43%	178,570,839	57.20%	*16*
17	751-800	22,349	17,333,940	188,682	36.08%	104,246,481	19.51%	22,482	17,412,293	396,358	78.91%	195,983,132	62.78%	*17*
18	801-850	22,194	18,321,750	210,876	40.32%	122,568,231	22.94%	18,138	14,953,076	414,496	82.52%	210,936,208	67.57%	*18*
19	851-900	21,820	19,102,706	232,696	44.49%	141,670,937	26.51%	14,957	13,078,194	429,453	85.50%	224,014,402	71.76%	*19*
20	901-950	21,512	19,906,181	254,208	48.60%	161,577,118	30.24%	12,072	11,159,118	441,525	87.90%	235,173,520	75.33%	*20*
21	951-1,000	21,075	20,556,989	275,283	52.63%	182,134,107	34.08%	9,871	9,619,399	451,396	89.87%	244,792,919	78.41%	*21*
22	1,001-1,100	40,800	42,841,157	316,083	60.44%	224,975,264	42.10%	14,969	15,672,208	466,365	92.85%	260,465,127	83.43%	*22*
23	1,101-1,200	38,007	43,687,651	354,090	67.70%	268,662,915	50.27%	10,100	11,589,331	476,465	94.86%	272,054,458	87.15%	*23*
24	1,201-1,300	34,090	42,588,243	388,180	74.22%	311,251,158	58.24%	6,989	8,719,213	483,454	96.25%	280,773,671	89.94%	*24*
25	1,301-1,400	29,495	39,784,747	417,675	79.86%	351,035,905	65.69%	4,911	6,618,029	488,365	97.23%	287,391,700	92.06%	*25*
26	1,401-1,500	25,049	36,292,113	442,724	84.65%	387,328,018	72.48%	3,579	5,179,411	491,944	97.94%	292,571,111	93.72%	*26*
27	1,501-1,600	20,093	31,114,089	462,817	88.49%	418,442,107	78.30%	2,689	4,163,762	494,633	98.48%	296,734,873	95.05%	*27*
28	1,601-1,700	15,926	26,244,673	478,743	91.54%	444,686,780	83.21%	1,779	2,932,019	496,412	98.83%	299,666,892	95.99%	*28*
29	1,701-1,800	11,895	20,799,017	490,638	93.81%	465,485,797	87.10%	1,393	2,433,994	497,805	99.11%	302,100,886	96.77%	*29*
30	1,801-1,900	8,868	16,382,728	499,506	95.51%	481,868,525	90.17%	1,036	1,913,270	498,841	99.31%	304,014,156	97.38%	*30*
31	1,901-2,000	6,563	12,781,551	506,069	96.76%	494,650,076	92.56%	731	1,423,218	499,572	99.46%	305,437,374	97.84%	*31*
32	2,001-2,250	9,317	19,638,865	515,386	98.54%	514,288,941	96.24%	1,182	2,496,897	500,754	99.69%	307,934,271	98.64%	*32*
33	2,251-2,500	3,994	9,412,914	519,380	99.31%	523,701,855	98.00%	620	1,461,758	501,374	99.82%	309,396,029	99.11%	*33*
34	2,501-3,000	2,579	6,935,159	521,959	99.80%	530,637,014	99.30%	576	1,551,208	501,950	99.93%	310,947,237	99.61%	*34*
35	3,001-4,000	879	2,924,158	522,838	99.97%	533,561,172	99.84%	268	903,944	502,218	99.99%	311,851,181	99.89%	*35*
36	4,001-5,000	127	556,436	522,965	99.99%	534,117,608	99.95%	50	220,225	502,268	100.00%	312,071,406	99.97%	*36*
37	5,001-10,000	46	285,467	523,011	100.00%	534,403,075	100.00%	18	96,589	502,286	100.00%	312,167,995	100.00%	*37*
38	10,001-20,000	-	-	523,011	100.00%	534,403,075	100.00%	1	11,041	502,287	100.00%	312,179,036	100.00%	*38*
39	over 20,000	-	-	523,011	100.00%	534,403,075	100.00%	-	-	502,287	100.00%	312,179,036	100.00%	*39*

Average Number of Customers:	87,169		Average Number of Customers:	83,715	
Average Consumption:	1,022	kWh per bill	Average Consumption:	622	kWh per bill
Median Consumption:	968	kWh per bill	Median Consumption:	564	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Fixed-Energy-Charge Plan Tier 3, Fixed-Energy-Charge Plan Tier 3 w/RCP, Fixed-Energy-Charge Plan Tier 3 w/E-3, Fixed-Energy-Charge Plan Tier 3 w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	153	-	153	0.12%	-	0.00%	254	-	254	0.22%	-	0.00%	*1*
2	1-50	390	10,863	543	0.44%	10,863	0.00%	808	19,710	1,062	0.90%	19,710	0.01%	*2*
3	51-100	365	27,757	908	0.74%	38,620	0.02%	777	58,424	1,839	1.56%	78,134	0.06%	*3*
4	101-150	373	46,691	1,281	1.04%	85,311	0.04%	703	87,653	2,542	2.16%	165,787	0.12%	*4*
5	151-200	379	66,391	1,660	1.34%	151,702	0.07%	669	117,640	3,211	2.73%	283,427	0.20%	*5*
6	201-250	369	83,199	2,029	1.64%	234,901	0.11%	661	149,687	3,872	3.29%	433,114	0.31%	*6*
7	251-300	381	104,961	2,410	1.95%	339,862	0.15%	776	214,001	4,648	3.95%	647,115	0.46%	*7*
8	301-350	419	137,081	2,829	2.29%	476,943	0.21%	968	316,406	5,616	4.77%	963,521	0.68%	*8*
9	351-400	425	160,318	3,254	2.64%	637,261	0.29%	1,383	519,680	6,999	5.95%	1,483,201	1.05%	*9*
10	401-450	546	232,632	3,800	3.08%	869,893	0.39%	1,859	793,611	8,858	7.53%	2,276,812	1.62%	*10*
11	451-500	664	316,283	4,464	3.62%	1,186,176	0.53%	2,263	1,076,239	11,121	9.45%	3,353,051	2.38%	*11*
12	501-550	766	403,051	5,230	4.24%	1,589,227	0.71%	2,790	1,467,099	13,911	11.82%	4,820,150	3.42%	*12*
13	551-600	991	570,942	6,221	5.04%	2,160,169	0.97%	3,610	2,079,098	17,521	14.89%	6,899,248	4.90%	*13*
14	601-650	1,161	727,315	7,382	5.98%	2,887,484	1.30%	4,070	2,547,566	21,591	18.35%	9,446,814	6.71%	*14*
15	651-700	1,427	964,053	8,809	7.14%	3,851,537	1.73%	4,534	3,063,769	26,125	22.20%	12,510,583	8.89%	*15*
16	701-750	1,752	1,272,028	10,561	8.55%	5,123,565	2.30%	5,018	3,642,512	31,143	26.46%	16,153,095	11.48%	*16*
17	751-800	1,906	1,479,605	12,467	10.10%	6,603,170	2.97%	5,246	4,068,057	36,389	30.92%	20,221,152	14.37%	*17*
18	801-850	2,227	1,839,552	14,694	11.90%	8,442,722	3.79%	5,406	4,462,591	41,795	35.51%	24,683,743	17.54%	*18*
19	851-900	2,409	2,109,824	17,103	13.85%	10,552,546	4.74%	5,264	4,608,303	47,059	39.99%	29,292,046	20.81%	*19*
20	901-950	2,643	2,446,515	19,746	15.99%	12,999,061	5.84%	5,109	4,727,973	52,168	44.33%	34,020,019	24.17%	*20*
21	951-1,000	2,718	2,651,585	22,464	18.20%	15,650,646	7.03%	4,926	4,802,275	57,094	48.51%	38,822,294	27.58%	*21*
22	1,001-1,100	5,859	6,159,219	28,323	22.94%	21,809,865	9.79%	9,108	9,554,857	66,202	56.25%	48,377,151	34.37%	*22*
23	1,101-1,200	6,015	6,923,405	34,338	27.81%	28,733,270	12.90%	7,829	8,998,073	74,031	62.90%	57,375,224	40.76%	*23*
24	1,201-1,300	6,165	7,706,346	40,503	32.81%	36,439,616	16.36%	6,727	8,401,060	80,758	68.62%	65,776,284	46.73%	*24*
25	1,301-1,400	6,160	8,313,112	46,663	37.80%	44,752,728	20.10%	5,587	7,534,861	86,345	73.37%	73,311,145	52.08%	*25*
26	1,401-1,500	6,170	8,946,396	52,833	42.79%	53,699,124	24.11%	4,607	6,674,705	90,952	77.28%	79,985,850	56.83%	*26*
27	1,501-1,600	6,167	9,556,456	59,000	47.79%	63,255,580	28.41%	3,931	6,087,303	94,883	80.62%	86,073,153	61.15%	*27*
28	1,601-1,700	6,108	10,080,109	65,108	52.74%	73,335,689	32.93%	3,219	5,308,788	98,102	83.36%	91,381,941	64.92%	*28*
29	1,701-1,800	6,022	10,539,155	71,130	57.62%	83,874,844	37.66%	2,773	4,849,597	100,875	85.71%	96,231,538	68.37%	*29*
30	1,801-1,900	5,630	10,414,554	76,760	62.18%	94,289,398	42.34%	2,221	4,103,169	103,096	87.60%	100,334,707	71.28%	*30*
31	1,901-2,000	5,259	10,254,589	82,019	66.44%	104,543,987	46.95%	1,935	3,770,850	105,031	89.24%	104,105,557	73.96%	*31*
32	2,001-2,250	11,430	24,220,147	93,449	75.69%	128,764,134	57.82%	3,592	7,604,406	108,623	92.30%	111,709,963	79.36%	*32*
33	2,251-2,500	8,626	20,440,215	102,075	82.68%	149,204,349	67.00%	2,491	5,901,659	111,114	94.41%	117,611,622	83.56%	*33*
34	2,501-3,000	10,265	27,896,255	112,340	91.00%	177,100,604	79.53%	2,962	8,069,501	114,076	96.93%	125,681,123	89.29%	*34*
35	3,001-4,000	7,374	24,986,905	119,714	96.97%	202,087,509	90.75%	2,281	7,769,819	116,357	98.87%	133,450,942	94.81%	*35*
36	4,001-5,000	2,085	9,222,497	121,799	98.66%	211,310,006	94.89%	717	3,154,728	117,074	99.48%	136,605,670	97.05%	*36*
37	5,001-10,000	1,525	9,515,619	123,324	99.89%	220,825,625	99.16%	573	3,537,251	117,647	99.96%	140,142,921	99.56%	*37*
38	10,001-20,000	118	1,444,008	123,442	99.99%	222,269,633	99.81%	35	412,610	117,682	99.99%	140,555,531	99.86%	*38*
39	over 20,000	15	419,975	123,457	100.00%	222,689,608	100.00%	8	200,820	117,690	100.00%	140,756,351	100.00%	*39*
		Average Number of Customers:		20,576				Average Number of Customers:		19,615				
		Average Consumption:		1,804	kWh per bill			Average Consumption:		1,196	kWh per bill			
		Median Consumption:		1,645	kWh per bill			Median Consumption:		1,019	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Time-of-Use 4-7 Weekdays, Time-of-Use 4-7 Weekdays w/RCP, Time-of-Use 4-7 Weekdays w/E-3, Time-of-Use 4-7 Weekdays w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	13,094	-	13,094	0.62%	-	0.00%	12,832	-	12,832	0.62%	-	0.00%	*1*
2	1-50	23,666	424,195	36,760	1.74%	424,195	0.02%	29,388	571,774	42,220	2.03%	571,774	0.04%	*2*
3	51-100	15,786	1,211,860	52,546	2.49%	1,636,055	0.06%	24,736	1,894,398	66,956	3.22%	2,466,172	0.15%	*3*
4	101-150	19,116	2,412,415	71,662	3.40%	4,048,470	0.14%	32,886	4,166,812	99,842	4.81%	6,632,984	0.42%	*4*
5	151-200	21,289	3,755,874	92,951	4.41%	7,804,344	0.28%	46,603	8,244,501	146,445	7.05%	14,877,485	0.93%	*5*
6	201-250	23,729	5,375,637	116,680	5.54%	13,179,981	0.47%	64,142	14,531,444	210,587	10.14%	29,408,929	1.84%	*6*
7	251-300	27,705	7,666,419	144,385	6.85%	20,846,400	0.74%	80,118	22,126,565	290,705	13.99%	51,535,494	3.23%	*7*
8	301-350	32,143	10,502,195	176,528	8.38%	31,348,595	1.11%	93,532	30,483,847	384,237	18.49%	82,019,341	5.14%	*8*
9	351-400	35,786	13,490,053	212,314	10.07%	44,838,648	1.59%	102,671	38,571,860	486,908	23.44%	120,591,201	7.56%	*9*
10	401-450	40,216	17,168,155	252,530	11.98%	62,006,803	2.19%	107,512	45,735,913	594,420	28.61%	166,327,114	10.43%	*10*
11	451-500	43,951	20,963,522	296,481	14.07%	82,970,325	2.93%	109,656	52,116,553	704,076	33.89%	218,443,667	13.69%	*11*
12	501-550	47,206	24,882,687	343,687	16.31%	107,853,012	3.82%	108,823	57,153,174	812,899	39.13%	275,596,841	17.28%	*12*
13	551-600	49,708	28,685,853	393,395	18.67%	136,538,865	4.83%	107,258	61,705,451	920,157	44.29%	337,302,292	21.14%	*13*
14	601-650	52,371	32,853,880	445,766	21.15%	169,392,745	5.99%	103,258	64,535,274	1,023,415	49.26%	401,837,566	25.19%	*14*
15	651-700	54,928	37,199,999	500,694	23.76%	206,592,744	7.31%	97,487	65,800,506	1,120,902	53.95%	467,638,072	29.31%	*15*
16	701-750	56,092	40,800,318	556,786	26.42%	247,393,062	8.75%	92,500	67,056,481	1,213,402	58.40%	534,694,553	33.52%	*16*
17	751-800	57,286	44,538,827	614,072	29.14%	291,931,889	10.33%	86,327	66,883,933	1,299,729	62.56%	601,578,486	37.71%	*17*
18	801-850	58,292	48,235,734	672,364	31.90%	340,167,623	12.03%	79,701	65,734,400	1,379,430	66.39%	667,312,886	41.83%	*18*
19	851-900	58,361	51,220,561	730,725	34.67%	391,388,184	13.84%	73,198	64,033,051	1,452,628	69.92%	731,345,937	45.85%	*19*
20	901-950	58,119	53,918,917	788,844	37.43%	445,307,101	15.75%	66,087	61,108,919	1,518,715	73.10%	792,454,856	49.68%	*20*
21	951-1,000	57,687	56,410,744	846,531	40.17%	501,717,845	17.75%	60,030	58,500,996	1,578,745	75.99%	850,955,852	53.34%	*21*
22	1,001-1,100	113,563	119,565,069	960,094	45.56%	621,282,914	21.98%	102,159	107,072,076	1,680,904	80.90%	958,027,928	60.06%	*22*
23	1,101-1,200	109,285	126,004,853	1,069,379	50.74%	747,287,767	26.43%	81,588	93,686,229	1,762,492	84.83%	1,051,714,157	65.93%	*23*
24	1,201-1,300	104,057	130,397,760	1,173,436	55.68%	877,685,527	31.05%	64,001	79,879,820	1,826,493	87.91%	1,131,593,977	70.94%	*24*
25	1,301-1,400	98,216	132,912,182	1,271,652	60.34%	1,010,597,709	35.75%	50,200	67,655,519	1,876,693	90.33%	1,199,249,496	75.18%	*25*
26	1,401-1,500	91,710	133,284,458	1,363,362	64.69%	1,143,882,167	40.46%	38,793	56,173,029	1,915,486	92.19%	1,255,422,525	78.70%	*26*
27	1,501-1,600	85,148	132,286,492	1,448,510	68.73%	1,276,168,659	45.14%	30,960	47,923,859	1,946,446	93.68%	1,303,346,384	81.70%	*27*
28	1,601-1,700	77,984	128,965,359	1,526,494	72.43%	1,405,134,018	49.70%	24,063	39,654,616	1,970,509	94.84%	1,343,001,000	84.19%	*28*
29	1,701-1,800	70,962	124,475,115	1,597,456	75.80%	1,529,609,133	54.11%	19,122	33,426,207	1,989,631	95.76%	1,376,427,207	86.28%	*29*
30	1,801-1,900	63,934	118,543,914	1,661,390	78.83%	1,648,153,047	58.30%	15,277	28,236,359	2,004,908	96.50%	1,404,663,566	88.05%	*30*
31	1,901-2,000	57,339	112,063,003	1,718,729	81.55%	1,760,216,050	62.27%	12,370	24,098,285	2,017,278	97.09%	1,428,761,851	89.56%	*31*
32	2,001-2,250	116,034	246,489,481	1,834,763	87.06%	2,006,705,531	70.98%	21,146	44,687,664	2,038,424	98.11%	1,473,449,515	92.36%	*32*
33	2,251-2,500	83,832	199,008,350	1,918,595	91.04%	2,205,713,881	78.02%	12,622	29,847,976	2,051,046	98.72%	1,503,297,491	94.24%	*33*
34	2,501-3,000	97,674	266,290,781	2,016,269	95.67%	2,472,004,662	87.44%	13,135	35,625,322	2,064,181	99.35%	1,538,922,813	96.47%	*34*
35	3,001-4,000	66,523	225,267,950	2,082,792	98.83%	2,697,272,612	95.41%	8,795	29,817,453	2,072,976	99.77%	1,568,740,266	98.34%	*35*
36	4,001-5,000	15,681	69,037,065	2,098,473	99.57%	2,766,309,677	97.85%	2,508	11,072,517	2,075,484	99.90%	1,579,812,783	99.03%	*36*
37	5,001-10,000	8,330	51,667,514	2,106,803	99.97%	2,817,977,191	99.68%	2,005	12,731,052	2,077,489	99.99%	1,592,543,835	99.83%	*37*
38	10,001-20,000	599	7,477,777	2,107,402	100.00%	2,825,454,968	99.95%	135	1,643,719	2,077,624	100.00%	1,594,187,554	99.93%	*38*
39	over 20,000	48	1,519,116	2,107,450	100.00%	2,826,974,084	100.00%	32	1,059,535	2,077,656	100.00%	1,595,247,089	100.00%	*39*

Average Number of Customers:	351,242		Average Number of Customers:	346,276	
Average Consumption:	1,341	kWh per bill	Average Consumption:	768	kWh per bill
Median Consumption:	1,186	kWh per bill	Median Consumption:	658	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **R-2, R-2 w/RCP, R-2 w/E-3, R-2 w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)							WINTER (November through April)						
				CUMULATIVE							CUMULATIVE				
				BILLS		CONSUMPTION					BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*		*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	1,114	-	1,114	0.19%	-	0.00%	*1*	649	-	649	0.11%	-	0.00%	*1*
2	1-50	2,320	57,850	3,434	0.59%	57,850	0.01%	*2*	3,077	77,782	3,726	0.62%	77,782	0.02%	*2*
3	51-100	2,736	208,539	6,170	1.06%	266,389	0.03%	*3*	4,102	318,919	7,828	1.31%	396,701	0.08%	*3*
4	101-150	3,235	405,738	9,405	1.62%	672,127	0.07%	*4*	6,351	807,443	14,179	2.38%	1,204,144	0.25%	*4*
5	151-200	3,697	650,569	13,102	2.26%	1,322,696	0.15%	*5*	9,652	1,710,801	23,831	4.00%	2,914,945	0.60%	*5*
6	201-250	4,323	977,157	17,425	3.00%	2,299,853	0.25%	*6*	14,702	3,338,003	38,533	6.46%	6,252,948	1.30%	*6*
7	251-300	5,183	1,433,154	22,608	3.89%	3,733,007	0.41%	*7*	19,851	5,484,709	58,384	9.79%	11,737,657	2.43%	*7*
8	301-350	6,073	1,982,282	28,681	4.94%	5,715,289	0.63%	*8*	24,858	8,106,723	83,242	13.96%	19,844,380	4.11%	*8*
9	351-400	6,938	2,608,860	35,619	6.13%	8,324,149	0.92%	*9*	28,202	10,593,385	111,444	18.69%	30,437,765	6.31%	*9*
10	401-450	7,834	3,336,623	43,453	7.48%	11,660,772	1.29%	*10*	30,785	13,101,531	142,229	23.85%	43,539,296	9.02%	*10*
11	451-500	8,731	4,156,875	52,184	8.98%	15,817,647	1.75%	*11*	31,460	14,958,204	173,689	29.12%	58,497,500	12.12%	*11*
12	501-550	9,692	5,096,685	61,876	10.65%	20,914,332	2.32%	*12*	31,707	16,658,400	205,396	34.44%	75,155,900	15.57%	*12*
13	551-600	10,492	6,040,746	72,368	12.46%	26,955,078	2.99%	*13*	31,377	18,049,895	236,773	39.70%	93,205,795	19.31%	*13*
14	601-650	10,997	6,881,904	83,365	14.35%	33,836,982	3.75%	*14*	30,684	19,185,966	267,457	44.84%	112,391,761	23.28%	*14*
15	651-700	11,642	7,865,096	95,007	16.36%	41,702,078	4.62%	*15*	29,507	19,921,022	296,964	49.79%	132,312,783	27.41%	*15*
16	701-750	12,330	8,945,508	107,337	18.48%	50,647,586	5.61%	*16*	28,171	20,420,505	325,135	54.51%	152,733,288	31.64%	*16*
17	751-800	12,740	9,881,188	120,077	20.67%	60,528,774	6.70%	*17*	26,446	20,493,625	351,581	58.95%	173,226,913	35.89%	*17*
18	801-850	13,098	10,810,198	133,175	22.93%	71,338,972	7.90%	*18*	24,419	20,143,824	376,000	63.04%	193,370,737	40.06%	*18*
19	851-900	13,432	11,757,813	146,607	25.24%	83,096,785	9.20%	*19*	22,999	20,121,445	398,999	66.90%	213,492,182	44.23%	*19*
20	901-950	13,695	12,671,407	160,302	27.60%	95,768,192	10.61%	*20*	21,030	19,449,034	420,029	70.42%	232,941,216	48.26%	*20*
21	951-1,000	13,689	13,347,839	173,991	29.96%	109,116,031	12.08%	*21*	19,009	18,525,784	439,038	73.61%	251,467,000	52.10%	*21*
22	1,001-1,100	28,242	29,669,288	202,233	34.82%	138,785,319	15.37%	*22*	32,578	34,156,437	471,616	79.07%	285,623,437	59.17%	*22*
23	1,101-1,200	28,535	32,818,811	230,768	39.73%	171,604,130	19.01%	*23*	26,082	29,942,687	497,698	83.45%	315,566,124	65.38%	*23*
24	1,201-1,300	28,065	35,075,849	258,833	44.56%	206,679,979	22.89%	*24*	20,863	26,044,074	518,561	86.94%	341,610,198	70.77%	*24*
25	1,301-1,400	27,200	36,713,672	286,033	49.25%	243,393,651	26.96%	*25*	16,211	21,853,845	534,772	89.66%	363,464,043	75.30%	*25*
26	1,401-1,500	26,901	38,997,742	312,934	53.88%	282,391,393	31.27%	*26*	12,679	18,354,970	547,451	91.79%	381,819,013	79.10%	*26*
27	1,501-1,600	25,980	40,259,120	338,914	58.35%	322,650,513	35.73%	*27*	9,720	15,046,404	557,171	93.42%	396,865,417	82.22%	*27*
28	1,601-1,700	24,518	40,448,244	363,432	62.57%	363,098,757	40.21%	*28*	7,818	12,888,629	564,989	94.73%	409,754,046	84.89%	*28*
29	1,701-1,800	23,065	40,354,628	386,497	66.54%	403,453,385	44.68%	*29*	6,028	10,539,098	571,017	95.74%	420,293,144	87.07%	*29*
30	1,801-1,900	21,610	39,958,636	408,107	70.26%	443,412,021	49.11%	*30*	4,655	8,604,477	575,672	96.52%	428,897,621	88.86%	*30*
31	1,901-2,000	19,957	38,900,002	428,064	73.70%	482,312,023	53.42%	*31*	3,674	7,156,065	579,346	97.14%	436,053,686	90.34%	*31*
32	2,001-2,250	42,502	90,062,241	470,566	81.02%	572,374,264	63.39%	*32*	6,055	12,793,971	585,401	98.15%	448,847,657	92.99%	*32*
33	2,251-2,500	31,972	75,711,945	502,538	86.52%	648,086,209	71.78%	*33*	3,537	8,363,677	588,938	98.74%	457,211,334	94.72%	*33*
34	2,501-3,000	39,890	108,573,809	542,428	93.39%	756,660,018	83.80%	*34*	3,648	9,904,551	592,586	99.36%	467,115,885	96.77%	*34*
35	3,001-4,000	28,415	96,011,213	570,843	98.28%	852,671,231	94.43%	*35*	2,492	8,463,450	595,078	99.77%	475,579,335	98.53%	*35*
36	4,001-5,000	6,699	29,379,702	577,542	99.43%	882,050,933	97.69%	*36*	813	3,587,757	595,891	99.91%	479,167,092	99.27%	*36*
37	5,001-10,000	3,143	19,123,129	580,685	99.98%	901,174,062	99.80%	*37*	513	3,209,057	596,404	100.00%	482,376,149	99.94%	*37*
38	10,001-20,000	144	1,741,638	580,829	100.00%	902,915,700	100.00%	*38*	26	309,520	596,430	100.00%	482,685,669	100.00%	*38*
39	over 20,000	1	21,235	580,830	100.00%	902,936,935	100.00%	*39*	-	-	596,430	100.00%	482,685,669	100.00%	*39*
		Average Number of Customers:		96,805					Average Number of Customers:		99,405				
		Average Consumption:		1,555	kWh per bill				Average Consumption:		809	kWh per bill			
		Median Consumption:		1,417	kWh per bill				Median Consumption:		703	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
B LL NG ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **R-2, R-2 w/RCP, R-2 w/E-3, R-2 w/E-4**
DESCR PTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF B LLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF B LLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	14,617	-	14,617	2.52%	-	0.00%	6,758	-	6,758	1.13%	-	0.00%	*1*
2	0-0.4	2,969	724	17,586	3.03%	724	0.02%	6,466	1,541	13,224	2.22%	1,541	0.06%	*2*
3	0.4-0.8	3,053	2,009	20,639	3.55%	2,733	0.08%	12,542	7,978	25,766	4.32%	9,519	0.40%	*3*
4	0 8-1.2	4,128	4,385	24,767	4.26%	7,118	0.20%	19,685	19,971	45,451	7.62%	29,490	1.24%	*4*
5	1 2-1.6	5,640	8,239	30,407	5.24%	15,357	0.44%	26,235	36,886	71,686	12.02%	66,376	2.79%	*5*
6	1 6-2.0	8,238	15,322	38,645	6.65%	30,679	0.88%	33,656	60,853	105,342	17.66%	127,229	5.34%	*6*
7	2 0-2.4	11,299	25,540	49,944	8.60%	56,219	1.61%	40,204	88,324	145,546	24.40%	215,553	9.05%	*7*
8	2.4-2.8	15,000	39,882	64,944	11.18%	96,101	2.75%	44,377	115,243	189,923	31.84%	330,795	13.89%	*8*
9	2 8-3.2	19,192	58,676	84,136	14.49%	154,777	4.43%	47,167	141,430	237,090	39.75%	472,226	19.83%	*9*
10	3 2-3.6	23,236	80,315	107,372	18.49%	235,092	6.73%	47,714	162,332	284,804	47.75%	634,558	26.64%	*10*
11	3 6-4.0	27,814	107,230	135,186	23.27%	342,322	9.80%	46,719	177,783	331,523	55.58%	812,341	34.11%	*11*
12	4 0-4.4	31,421	133,647	166,607	28.68%	475,970	13.63%	42,985	180,582	374,508	62.79%	992,923	41.69%	*12*
13	4.4-4.8	34,574	160,866	201,181	34.64%	636,836	18.23%	39,074	179,861	413,582	69.34%	1,172,784	49.24%	*13*
14	4 8-5.2	36,204	182,878	237,385	40.87%	819,713	23.47%	34,069	170,762	447,651	75.06%	1,343,545	56.41%	*14*
15	5 2-5.6	37,363	203,635	274,748	47.30%	1,023,348	29.29%	29,352	158,651	477,003	79.98%	1,502,196	63.07%	*15*
16	5 6-6 0	37,088	216,925	311,836	53.69%	1,240,273	35.50%	24,932	144,517	501,935	84.16%	1,646,712	69.14%	*16*
17	6 0-6.4	35,943	224,599	347,779	59.88%	1,464,872	41.93%	19,989	123,992	521,924	87.51%	1,770,704	74.34%	*17*
18	6.4-6.8	33,785	224,549	381,564	65.69%	1,689,421	48.36%	16,121	106,511	538,045	90.21%	1,877,215	78.81%	*18*
19	6 8-7.2	30,747	216,712	412,311	70.99%	1,906,133	54.56%	12,901	90,400	550,946	92.37%	1,967,615	82.61%	*19*
20	7 2-7.6	27,261	203,006	439,572	75.68%	2,109,139	60.38%	9,726	72,004	560,672	94.00%	2,039,619	85.63%	*20*
21	7 6-8 0	23,902	187,519	463,474	79.80%	2,296,657	65.74%	7,619	59,438	568,291	95.28%	2,099,057	88.13%	*21*
22	8 0-8.4	20,772	171,274	484,246	83.37%	2,467,931	70.65%	6,021	49,399	574,312	96.29%	2,148,456	90.20%	*22*
23	8.4-8 8	17,315	149,665	501,561	86.35%	2,617,596	74.93%	4,597	39,525	578,909	97.06%	2,187,982	91.86%	*23*
24	8 8-9 2	14,311	129,423	515,872	88.82%	2,747,019	78.64%	3,453	31,045	582,362	97.64%	2,219,026	93.16%	*24*
25	9 2-9 6	11,815	111,579	527,687	90.85%	2,858,597	81.83%	2,667	25,047	585,029	98.09%	2,244,073	94.21%	*25*
26	9.6-10.0	9,664	95,136	537,351	92.51%	2,953,733	84.55%	1,939	18,932	586,968	98.41%	2,263,005	95.01%	*26*
27	10 0-10.4	7,673	78,599	545,024	93.84%	3,032,333	86.80%	1,646	16,802	588,614	98.69%	2,279,807	95.72%	*27*
28	10.4-10.8	6,312	67,163	551,336	94.92%	3,099,495	88.73%	1,287	13,516	589,901	98.91%	2,293,323	96.28%	*28*
29	10 8-11.2	4,998	55,196	556,334	95.78%	3,154,691	90.31%	1,037	11,372	590,938	99.08%	2,304,695	96.76%	*29*
30	11 2-12.0	7,536	87,608	563,870	97.08%	3,242,299	92.81%	1,441	16,650	592,379	99.32%	2,321,344	97.46%	*30*
31	12.0 - 13 0	5,874	73,490	569,744	98.09%	3,315,789	94.92%	1,238	15,251	593,617	99.53%	2,336,595	98.10%	*31*
32	13.0 - 14 0	3,631	49,052	573,375	98.72%	3,364,840	96.32%	843	11,359	594,460	99.67%	2,347,954	98.58%	*32*
33	14.0 - 15 0	2,249	32,634	575,624	99.10%	3,397,474	97.26%	579	8,410	595,039	99.77%	2,356,364	98.93%	*33*
34	15.0 - 16 0	1,532	23,780	577,156	99.37%	3,421,254	97.94%	420	6,466	595,459	99.84%	2,362,830	99.20%	*34*
35	16.0 - 17 0	1,075	17,766	578,231	99.55%	3,439,019	98.45%	252	4,171	595,711	99.88%	2,367,001	99.38%	*35*
36	17.0 - 18 0	694	12,171	578,925	99.67%	3,451,190	98.79%	187	3,283	595,898	99.91%	2,370,283	99.51%	*36*
37	18.0 - 19 0	446	8,247	579,371	99.75%	3,459,437	99.03%	125	2,309	596,023	99.93%	2,372,592	99.61%	*37*
38	19.0 - 20 0	392	7,652	579,763	99.82%	3,467,089	99.25%	110	2,145	596,133	99.95%	2,374,737	99.70%	*38*
39	20.0 - 25 0	732	16,204	580,495	99.94%	3,483,293	99.71%	209	4,524	596,342	99.99%	2,379,261	99.89%	*39*
40	25.0 - 30 0	219	5,900	580,714	99.98%	3,489,193	99.88%	50	1,305	596,392	99.99%	2,380,567	99.95%	*40*
41	Over 30 0	116	4,146	580,830	100.00%	3,493,339	100.00%	38	1,302	596,430	100.00%	2,381,869	100.00%	*41*
		Average Number of Customers:		96,805				Average Number of Customers:		99,405				
		Average Load:		6.0	kW per bill			Average Load:		4.0	kW per bill			
		Median Load:		5.8	kW per bill			Median Load:		3.8	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Time-of-Use 4-7 Weekdays - Demand, Time-of-Use 4-7 Weekdays - Demand w/RCP, Time-of-Use 4-7 Weekdays - Demand w/E-3, Time-of-Use 4-7 Weekdays - Demand w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	3,101	-	3,101	0.20%	-	0.00%	2,531	-	2,531	0.16%	-	0.00%	1
2	1-50	6,868	172,483	9,969	0.64%	172,483	0.01%	10,870	275,086	13,401	0.85%	275,086	0.02%	2
3	51-100	7,507	576,417	17,476	1.12%	748,900	0.02%	11,462	875,954	24,863	1.58%	1,151,040	0.07%	3
4	101-150	8,648	1,090,098	26,124	1.68%	1,838,998	0.06%	14,616	1,846,713	39,479	2.50%	2,997,753	0.17%	4
5	151-200	9,496	1,672,974	35,620	2.29%	3,511,972	0.12%	19,477	3,440,348	58,956	3.74%	6,438,101	0.37%	5
6	201-250	10,486	2,373,905	46,106	2.96%	5,885,877	0.20%	25,811	5,845,334	84,767	5.37%	12,283,435	0.71%	6
7	251-300	12,020	3,325,762	58,126	3.73%	9,211,639	0.31%	33,106	9,145,492	117,873	7.47%	21,428,927	1.23%	7
8	301-350	13,611	4,446,127	71,737	4.61%	13,657,766	0.45%	39,691	12,937,328	157,564	9.98%	34,366,255	1.98%	8
9	351-400	15,303	5,768,275	87,040	5.59%	19,426,041	0.65%	44,673	16,788,718	202,237	12.81%	51,154,973	2.95%	9
10	401-450	16,662	7,110,542	103,702	6.66%	26,536,583	0.88%	49,463	21,047,502	251,700	15.95%	72,202,475	4.16%	10
11	451-500	18,128	8,648,847	121,830	7.83%	35,185,430	1.17%	52,326	24,874,124	304,026	19.26%	97,076,599	5.59%	11
12	501-550	19,832	10,456,041	141,662	9.10%	45,641,471	1.52%	54,367	28,562,617	358,393	22.71%	125,639,216	7.24%	12
13	551-600	20,933	12,085,445	162,595	10.45%	57,726,916	1.92%	56,258	32,361,285	414,651	26.27%	158,000,501	9.10%	13
14	601-650	22,186	13,917,565	184,781	11.87%	71,644,481	2.39%	57,110	35,705,237	471,761	29.89%	193,705,738	11.16%	14
15	651-700	23,503	15,921,894	208,284	13.38%	87,566,375	2.92%	57,550	38,857,806	529,311	33.54%	232,563,544	13.40%	15
16	701-750	24,396	17,745,351	232,680	14.95%	105,311,726	3.51%	58,041	42,080,174	587,352	37.21%	274,643,718	15.82%	16
17	751-800	24,993	19,432,549	257,673	16.56%	124,744,275	4.16%	57,019	44,187,985	644,371	40.83%	318,831,703	18.37%	17
18	801-850	26,091	21,592,859	283,764	18.23%	146,337,134	4.87%	56,050	46,241,856	700,421	44.38%	365,073,559	21.03%	18
19	851-900	26,803	23,523,649	310,567	19.96%	169,860,783	5.66%	55,341	48,419,341	755,762	47.88%	413,492,900	23.82%	19
20	901-950	27,325	25,353,311	337,892	21.71%	195,214,094	6.50%	53,031	49,050,523	808,793	51.24%	462,543,423	26.65%	20
21	951-1,000	27,621	27,012,549	365,513	23.49%	222,226,643	7.40%	51,231	49,946,756	860,024	54.49%	512,490,179	29.53%	21
22	1,001-1,100	57,090	60,139,972	422,603	27.15%	282,366,615	9.41%	95,560	100,263,961	955,584	60.55%	612,754,140	35.30%	22
23	1,101-1,200	58,791	67,815,833	481,394	30.93%	350,182,448	11.67%	86,098	98,907,007	1,041,682	66.00%	711,661,147	41.00%	23
24	1,201-1,300	59,074	74,072,940	540,468	34.73%	424,255,388	14.13%	76,239	95,202,670	1,117,921	70.83%	806,863,817	46.48%	24
25	1,301-1,400	59,636	80,738,027	600,104	38.56%	504,993,415	16.82%	66,971	90,320,805	1,184,892	75.07%	897,184,622	51.69%	25
26	1,401-1,500	59,581	86,628,268	659,685	42.39%	591,621,683	19.71%	58,230	84,344,201	1,243,122	78.76%	981,528,823	56.55%	26
27	1,501-1,600	58,739	91,295,973	718,424	46.16%	682,917,656	22.75%	49,272	76,294,743	1,292,394	81.89%	1,057,823,566	60.94%	27
28	1,601-1,700	57,172	94,583,542	775,596	49.84%	777,501,198	25.90%	42,033	69,281,024	1,334,427	84.55%	1,127,104,590	64.93%	28
29	1,701-1,800	56,090	98,411,203	831,686	53.44%	875,912,401	29.18%	35,435	61,940,877	1,369,862	86.79%	1,189,045,467	68.50%	29
30	1,801-1,900	53,851	99,869,243	885,537	56.90%	975,781,644	32.50%	29,715	54,921,609	1,399,577	88.68%	1,243,967,076	71.67%	30
31	1,901-2,000	51,721	101,106,084	937,258	60.22%	1,076,887,728	35.87%	25,117	48,931,358	1,424,694	90.27%	1,292,898,434	74.49%	31
32	2,001-2,250	118,908	253,002,655	1,056,166	67.86%	1,329,890,383	44.30%	46,387	98,124,302	1,471,081	93.21%	1,391,022,736	80.14%	32
33	2,251-2,500	102,162	242,910,884	1,158,328	74.43%	1,572,801,267	52.39%	30,442	72,016,513	1,501,523	95.14%	1,463,039,249	84.29%	33
34	2,501-3,000	153,625	420,901,700	1,311,953	84.30%	1,993,702,967	66.41%	34,486	93,749,409	1,536,009	97.32%	1,556,788,658	89.69%	34
35	3,001-4,000	154,433	528,760,385	1,466,386	94.22%	2,522,463,352	84.03%	26,332	89,513,286	1,562,341	98.99%	1,646,301,944	94.85%	35
36	4,001-5,000	53,444	236,458,680	1,519,830	97.66%	2,758,922,032	91.90%	8,337	36,858,517	1,570,678	99.52%	1,683,160,461	96.97%	36
37	5,001-10,000	34,135	212,353,868	1,553,965	99.85%	2,971,275,900	98.98%	6,990	44,252,766	1,577,668	99.96%	1,727,413,227	99.52%	37
38	10,001-20,000	2,249	28,235,272	1,556,214	99.99%	2,999,511,172	99.92%	598	7,514,185	1,578,266	100.00%	1,734,927,412	99.95%	38
39	over 20,000	99	2,465,788	1,556,313	100.00%	3,001,976,960	100.00%	35	846,394	1,578,301	100.00%	1,735,773,806	100.00%	39
		Average Number of Customers:		259,386				Average Number of Customers:		263,050				
		Average Consumption:		1,929	kWh per bill			Average Consumption:		1,100	kWh per bill			
		Median Consumption:		1,705	kWh per bill			Median Consumption:		932	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
B LL NG ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Time-of-Use 4-7 Weekdays - Demand, Time-of-Use 4-7 Weekdays - Demand w/RCP, Time-of-Use 4-7 Weekdays - Demand w/E-3, Time-of-Use 4-7 Weekdays - Demand w/E-4**
DESCR PTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		LOAD				B LLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF B LLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF B LLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	9,041	-	9,041	0 58%	-	0 00%	12,560	-	12,560	0 80%	-	0 00%	*1*
2	0-0.4	15,764	3,817	24,805	1 59%	3,817	0 04%	24,097	5,481	36,657	2 32%	5,481	0 08%	*2*
3	0.4-0 8	16,079	10,576	40,884	2 63%	14,392	0.14%	36,473	23,233	73,130	4 63%	28,714	0.43%	*3*
4	0 8-1 2	19,909	21,031	60,793	3 91%	35,423	0 36%	54,137	55,909	127,267	8 06%	84,622	1 25%	*4*
5	1 2-1 6	23,910	34,825	84,703	5.44%	70,248	0.71%	69,668	100,009	196,935	12.48%	184,631	2.74%	*5*
6	1 6-2 0	29,407	54,577	114,110	7 33%	124,825	1 25%	86,141	158,357	283,076	17 94%	342,988	5 08%	*6*
7	2 0-2.4	36,620	82,641	150,730	9 69%	207,466	2 08%	101,533	227,472	384,609	24 37%	570,460	8.45%	*7*
8	2.4-2 8	44,748	118,836	195,478	12 56%	326,301	3 28%	111,278	293,977	495,887	31.42%	864,437	12 81%	*8*
9	2 8-3 2	53,712	164,039	249,190	16 01%	490,340	4 92%	116,199	353,660	612,086	38.78%	1,218,097	18 04%	*9*
10	3 2-3 6	61,337	211,890	310,527	19 95%	702,230	7 05%	115,834	398,989	727,920	46.12%	1,617,086	23 95%	*10*
11	3 6-4 0	70,743	272,590	381,270	24 50%	974,820	9.78%	112,575	432,541	840,495	53 25%	2,049,627	30 36%	*11*
12	4 0-4.4	77,091	327,788	458,361	29.45%	1,302,608	13 07%	104,369	442,906	944,864	59 87%	2,492,533	36 92%	*12*
13	4.4-4 8	83,367	387,806	541,728	34 81%	1,690,414	16 97%	96,388	447,662	1,041,252	65 97%	2,940,194	43 55%	*13*
14	4 8-5 2	85,794	433,310	627,522	40 32%	2,123,724	21 32%	85,890	433,064	1,127,142	71.41%	3,373,259	49 97%	*14*
15	5 2-5 6	86,878	473,532	714,400	45 90%	2,597,255	26 07%	75,764	412,479	1,202,906	76 22%	3,785,738	56 08%	*15*
16	5 6-6 0	85,555	500,388	799,955	51.40%	3,097,643	31 09%	64,968	379,517	1,267,874	80 33%	4,165,255	61.70%	*16*
17	6 0-6.4	82,013	512,563	881,968	56 67%	3,610,206	36 24%	54,507	340,294	1,322,381	83.79%	4,505,549	66.74%	*17*
18	6.4-6 8	78,186	519,770	960,154	61 69%	4,129,976	41.45%	45,212	300,350	1,367,593	86 65%	4,805,899	71.19%	*18*
19	6 8-7 2	72,662	512,091	1,032,816	66 36%	4,642,067	46 59%	37,898	266,923	1,405,491	89 05%	5,072,822	75.15%	*19*
20	7 2-7 6	66,130	492,488	1,098,946	70 61%	5,134,555	51 54%	30,402	226,241	1,435,893	90 98%	5,299,063	78 50%	*20*
21	7 6-8 0	59,496	466,901	1,158,442	74.44%	5,601,456	56 22%	24,748	194,089	1,460,641	92 55%	5,493,152	81 37%	*21*
22	8 0-8.4	53,398	440,383	1,211,840	77 87%	6,041,838	60 64%	20,480	168,815	1,481,121	93 84%	5,661,966	83 87%	*22*
23	8.4-8 8	46,768	404,365	1,258,608	80 87%	6,446,203	64.70%	16,536	142,938	1,497,657	94 89%	5,804,904	85 99%	*23*
24	8 8-9 2	41,040	371,261	1,299,648	83 51%	6,817,464	68.43%	12,970	117,275	1,510,627	95.71%	5,922,179	87.73%	*24*
25	9 2-9 6	35,691	337,127	1,335,339	85 80%	7,154,590	71 81%	11,054	104,419	1,521,681	96.41%	6,026,597	89 28%	*25*
26	9.6-10.0	30,651	301,777	1,365,990	87.77%	7,456,367	74 84%	8,412	82,784	1,530,093	96 95%	6,109,381	90 50%	*26*
27	10 0-10.4	26,438	270,929	1,392,428	89.47%	7,727,296	77 56%	6,994	71,668	1,537,087	97 39%	6,181,050	91 56%	*27*
28	10.4-10 8	22,578	240,405	1,415,006	90 92%	7,967,701	79 97%	5,709	60,779	1,542,796	97.75%	6,241,829	92.46%	*28*
29	10 8-11 2	19,042	210,367	1,434,048	92.14%	8,178,068	82 08%	4,732	52,302	1,547,528	98 05%	6,294,130	93 24%	*29*
30	11 2-12 0	30,239	351,865	1,464,287	94 09%	8,529,933	85 61%	7,370	85,801	1,554,898	98 52%	6,379,931	94 51%	*30*
31	12.0 - 13.0	26,253	328,613	1,490,540	95.77%	8,858,547	88 91%	6,103	76,450	1,561,001	98 90%	6,456,381	95 64%	*31*
32	13.0 - 14.0	18,173	245,718	1,508,713	96 94%	9,104,264	91 38%	4,496	60,750	1,565,497	99.19%	6,517,131	96 54%	*32*
33	14.0 - 15.0	12,426	180,421	1,521,139	97.74%	9,284,685	93.19%	3,072	44,511	1,568,569	99 38%	6,561,643	97 20%	*33*
34	15.0 - 16.0	9,091	141,156	1,530,230	98 32%	9,425,841	94 61%	2,457	38,160	1,571,026	99 54%	6,599,803	97.77%	*34*
35	16.0 - 17.0	6,162	101,896	1,536,392	98.72%	9,527,737	95 63%	1,647	27,285	1,572,673	99 64%	6,627,088	98.17%	*35*
36	17.0 - 18.0	4,506	79,045	1,540,898	99 01%	9,606,782	96.42%	1,235	21,682	1,573,908	99.72%	6,648,770	98.49%	*36*
37	18.0 - 19.0	3,098	57,384	1,543,996	99 21%	9,664,166	97 00%	784	14,474	1,574,692	99.77%	6,663,244	98.71%	*37*
38	19.0 - 20.0	2,689	52,508	1,546,685	99 38%	9,716,673	97 53%	821	16,030	1,575,513	99 82%	6,679,273	98 94%	*38*
39	20.0 - 25.0	6,032	133,145	1,552,717	99.77%	9,849,818	98 86%	1,757	38,967	1,577,270	99 93%	6,718,240	99 52%	*39*
40	25.0 - 30.0	2,108	57,314	1,554,825	99 90%	9,907,132	99.44%	602	16,317	1,577,872	99 97%	6,734,557	99.76%	*40*
41	Over 30.0	1,488	56,105	1,556,313	100 00%	9,963,237	100 00%	429	15,981	1,578,301	100 00%	6,750,538	100 00%	*41*
	Average Number of Customers:			259,386				Average Number of Customers:		263,050				
	Average Load:			6.4	kW per bill			Average Load:		4 3	kW per bill			
	Median Load:			5 9	kW per bill			Median Load:		3 9	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Tech Time-of-Use 3-8 Weekdays - Demand, Tech Time-of-Use 3-8 Weekdays - Demand w/RCP, Tech Time-of-Use 3-8 Weekdays - Demand w/E-3, Tech Time-of-Use 3-8 Weekdays - Demand w/E-4**

DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1
2	1-50	3	108	3	0.91%	108	0.02%	10	253	10	2.99%	253	0.07%	2
3	51-100	3	181	6	1.82%	289	0.05%	3	173	13	3.89%	426	0.12%	3
4	101-150	1	103	7	2.12%	392	0.07%	1	142	14	4.19%	568	0.16%	4
5	151-200	5	921	12	3.64%	1,313	0.23%	7	1,239	21	6.29%	1,807	0.50%	5
6	201-250	5	1,129	17	5.15%	2,442	0.43%	4	963	25	7.49%	2,770	0.77%	6
7	251-300	7	1,869	24	7.27%	4,311	0.76%	4	1,132	29	8.68%	3,902	1.08%	7
8	301-350	6	1,951	30	9.09%	6,262	1.11%	6	1,962	35	10.48%	5,864	1.62%	8
9	351-400	1	380	31	9.39%	6,642	1.17%	12	4,523	47	14.07%	10,387	2.87%	9
10	401-450	10	4,255	41	12.42%	10,897	1.93%	12	5,107	59	17.66%	15,494	4.28%	10
11	451-500	11	5,248	52	15.76%	16,145	2.85%	12	5,752	71	21.26%	21,246	5.87%	11
12	501-550	5	2,608	57	17.27%	18,753	3.31%	10	5,301	81	24.25%	26,547	7.34%	12
13	551-600	9	5,159	66	20.00%	23,912	4.23%	12	6,987	93	27.84%	33,534	9.27%	13
14	601-650	15	9,470	81	24.55%	33,382	5.90%	15	9,488	108	32.34%	43,022	11.89%	14
15	651-700	9	6,122	90	27.27%	39,504	6.98%	13	8,824	121	36.23%	51,846	14.33%	15
16	701-750	15	10,962	105	31.82%	50,466	8.92%	9	6,529	130	38.92%	58,375	16.14%	16
17	751-800	6	4,706	111	33.64%	55,172	9.75%	14	10,990	144	43.11%	69,365	19.17%	17
18	801-850	10	8,343	121	36.67%	63,515	11.22%	10	8,249	154	46.11%	77,614	21.46%	18
19	851-900	8	7,036	129	39.09%	70,551	12.47%	12	10,577	166	49.70%	88,191	24.38%	19
20	901-950	8	7,406	137	41.52%	77,957	13.78%	12	11,080	178	53.29%	99,271	27.44%	20
21	951-1,000	6	5,938	143	43.33%	83,895	14.83%	6	5,803	184	55.09%	105,074	29.05%	21
22	1,001-1,100	12	12,671	155	46.97%	96,566	17.07%	20	20,934	204	61.08%	126,008	34.83%	22
23	1,101-1,200	6	6,764	161	48.79%	103,330	18.26%	19	21,987	223	66.77%	147,995	40.91%	23
24	1,201-1,300	3	3,790	164	49.70%	107,120	18.93%	20	24,789	243	72.75%	172,784	47.76%	24
25	1,301-1,400	14	18,938	178	53.94%	126,058	22.28%	9	12,191	252	75.45%	184,975	51.13%	25
26	1,401-1,500	11	16,079	189	57.27%	142,137	25.12%	12	17,416	264	79.04%	202,391	55.95%	26
27	1,501-1,600	7	10,849	196	59.39%	152,986	27.04%	11	17,061	275	82.34%	219,452	60.66%	27
28	1,601-1,700	4	6,609	200	60.61%	159,595	28.20%	11	18,337	286	85.63%	237,789	65.73%	28
29	1,701-1,800	9	15,819	209	63.33%	175,414	31.00%	4	7,068	290	86.83%	244,857	67.69%	29
30	1,801-1,900	3	5,576	212	64.24%	180,990	31.99%	4	7,529	294	88.02%	252,386	69.77%	30
31	1,901-2,000	6	11,790	218	66.06%	192,780	34.07%	6	11,701	300	89.82%	264,087	73.00%	31
32	2,001-2,250	9	19,504	227	68.79%	212,284	37.52%	13	27,714	313	93.71%	291,801	80.66%	32
33	2,251-2,500	19	45,334	246	74.55%	257,618	45.53%	6	13,911	319	95.51%	305,712	84.51%	33
34	2,501-3,000	33	89,465	279	84.55%	347,083	61.34%	5	13,757	324	97.01%	319,469	88.31%	34
35	3,001-4,000	29	102,398	308	93.33%	449,481	79.44%	3	9,731	327	97.90%	329,200	91.00%	35
36	4,001-5,000	14	62,506	322	97.58%	511,987	90.48%	5	22,493	332	99.40%	351,693	97.22%	36
37	5,001-10,000	8	53,859	330	100.00%	565,846	100.00%	2	10,059	334	100.00%	361,752	100.00%	37
38	10,001-20,000	-	-	330	100.00%	565,846	100.00%	-	-	334	100.00%	361,752	100.00%	38
39	over 20,000	-	-	330	100.00%	565,846	100.00%	-	-	334	100.00%	361,752	100.00%	39
	Average Number of Customers:			55				Average Number of Customers:		56				
	Average Consumption:			1,715	kWh per bill			Average Consumption:		1,083	kWh per bill			
	Median Consumption:			1,315	kWh per bill			Median Consumption:		907	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
B LL NG ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **Tech Time-of-Use 3-8 Weekdays - Demand, Tech Time-of-Use 3-8 Weekdays - Demand w/RCP, Tech Time-of-Use 3-8 Weekdays - Demand w/E-3, Tech Time-of-Use 3-8 Weekdays - Demand w/E-4**

DESCRIPTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF B LLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	11	-	11	3.33%	-	0.00%	18	-	18	5.39%	-	0.00%	*1*
2	0-0.4	26	6	37	11.21%	6	0.33%	40	9	58	17.37%	9	0.80%	*2*
3	0.4-0 8	10	6	47	14.24%	12	0.66%	20	13	78	23.35%	22	1.94%	*3*
4	0 8-1 2	13	14	60	18.18%	26	1.42%	19	20	97	29.04%	41	3.68%	*4*
5	1 2-1 6	15	22	75	22.73%	47	2.61%	11	15	108	32.34%	56	5.04%	*5*
6	1 6-2 0	14	26	89	26.97%	74	4.05%	30	56	138	41.32%	112	10.01%	*6*
7	2 0-2.4	14	32	103	31.21%	105	5.78%	21	48	159	47.60%	159	14.27%	*7*
8	2.4-2 8	13	34	116	35.15%	139	7.66%	13	30	172	51.50%	189	16.92%	*8*
9	2 8-3 2	13	40	129	39.09%	179	9.86%	14	43	186	55.69%	231	20.73%	*9*
10	3 2-3 6	11	38	140	42.42%	217	11.92%	14	49	200	59.88%	280	25.09%	*10*
11	3 6-4 0	15	57	155	46.97%	274	15.05%	18	62	218	65.27%	342	30.62%	*11*
12	4 0-4.4	11	47	166	50.30%	321	17.64%	18	76	236	70.66%	418	37.47%	*12*
13	4.4-4 8	7	32	173	52.42%	353	19.41%	19	89	255	76.35%	506	45.40%	*13*
14	4 8-5 2	9	45	182	55.15%	399	21.90%	8	40	263	78.74%	547	49.00%	*14*
15	5 2-5 6	10	55	192	58.18%	453	24.91%	12	67	275	82.34%	613	54.97%	*15*
16	5 6-6 0	14	81	206	62.42%	534	29.36%	9	53	284	85.03%	666	59.71%	*16*
17	6 0-6.4	7	44	213	64.55%	578	31.75%	7	43	291	87.13%	709	63.59%	*17*
18	6.4-6 8	9	60	222	67.27%	638	35.04%	8	53	299	89.52%	762	68.34%	*18*
19	6 8-7 2	13	91	235	71.21%	729	40.06%	4	28	303	90.72%	791	70.88%	*19*
20	7 2-7 6	6	45	241	73.03%	774	42.53%	6	44	309	92.51%	835	74.85%	*20*
21	7 6-8 0	5	39	246	74.55%	813	44.69%	2	16	311	93.11%	851	76.25%	*21*
22	8 0-8.4	3	25	249	75.45%	838	46.05%	1	8	312	93.41%	859	76.98%	*22*
23	8.4-8 8	7	61	256	77.58%	899	49.40%	-	-	312	93.41%	859	76.98%	*23*
24	8 8-9 2	2	18	258	78.18%	917	50.39%	4	36	316	94.61%	895	80.20%	*24*
25	9 2-9 6	7	67	265	80.30%	984	54.06%	-	-	316	94.61%	895	80.20%	*25*
26	9.6-10.0	6	59	271	82.12%	1,043	57.30%	2	20	318	95.21%	914	81.98%	*26*
27	10 0-10.4	11	113	282	85.45%	1,155	63.50%	1	10	319	95.51%	925	82.89%	*27*
28	10.4-10.8	6	64	288	87.27%	1,219	67.02%	1	11	320	95.81%	935	83.84%	*28*
29	10 8-11.2	5	55	293	88.79%	1,274	70.04%	4	45	324	97.01%	980	87.83%	*29*
30	11 2-12.0	7	80	300	90.91%	1,355	74.46%	4	46	328	98.20%	1,026	91.98%	*30*
31	12.0 - 13 0	4	50	304	92.12%	1,404	77.19%	-	-	328	98.20%	1,026	91.98%	*31*
32	13.0 - 14 0	11	149	315	95.45%	1,553	85.38%	2	28	330	98.80%	1,054	94.49%	*32*
33	14.0 - 15 0	4	59	319	96.67%	1,612	88.62%	3	43	333	99.70%	1,097	98.35%	*33*
34	15.0 - 16 0	2	31	321	97.27%	1,643	90.33%	-	-	333	99.70%	1,097	98.35%	*34*
35	16.0 - 17 0	4	66	325	98.48%	1,709	93.95%	-	-	333	99.70%	1,097	98.35%	*35*
36	17.0 - 18 0	-	-	325	98.48%	1,709	93.95%	-	-	333	99.70%	1,097	98.35%	*36*
37	18.0 - 19 0	1	19	326	98.79%	1,728	94.99%	1	18	334	100.00%	1,115	100.00%	*37*
38	19.0 - 20 0	-	-	326	98.79%	1,728	94.99%	-	-	334	100.00%	1,115	100.00%	*38*
39	20.0 - 25 0	3	66	329	99.70%	1,794	98.62%	-	-	334	100.00%	1,115	100.00%	*39*
40	25.0 - 30 0	1	25	330	100.00%	1,819	100.00%	-	-	334	100.00%	1,115	100.00%	*40*
41	Over 30.0	-	-	330	100.00%	1,819	100.00%	-	-	334	100.00%	1,115	100.00%	*41*
		Average Number of Customers:		55				Average Number of Customers:		56				
		Average Load:		5.5	kW per bill			Average Load:		3 3	kW per bill			
		Median Load:		4.4	kW per bill			Median Load:		2.7	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-20**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						W NTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	71	-	71	3.18%	-	0.00%	91	-	91	4.09%	-	0 00%	*1*
2	1-100	16	477	87	3.89%	477	0.00%	25	965	116	5.21%	965	0 01%	*2*
3	101-200	15	2,322	102	4.56%	2,799	0.01%	17	2,890	133	5.97%	3,855	0 04%	*3*
4	201-300	12	2,997	114	5.10%	5,796	0.03%	38	9,868	171	7.68%	13,723	0.13%	*4*
5	301-400	12	4,337	126	5.64%	10,133	0.05%	28	9,679	199	8.94%	23,402	0 22%	*5*
6	401-500	11	4,923	137	6.13%	15,056	0.07%	37	16,755	236	10.60%	40,157	0 38%	*6*
7	501-750	50	31,518	187	8.37%	46,574	0.22%	100	62,438	336	15.09%	102,595	0 97%	*7*
8	751-1,000	48	42,079	235	10.51%	88,653	0.42%	105	92,452	441	19.81%	195,047	1 84%	*8*
9	1,001-1,500	123	155,322	358	16.02%	243,975	1.15%	217	271,307	658	29.56%	466,354	4 39%	*9*
10	1,501-2,000	126	223,175	484	21.66%	467,150	2.20%	198	345,162	856	38.45%	811,516	7 64%	*10*
11	2,001-3,000	202	502,315	686	30.69%	969,465	4.56%	306	772,325	1,162	52.20%	1,583,841	14 91%	*11*
12	3,001-4,000	208	726,178	894	40.00%	1,695,643	7.98%	276	976,897	1,438	64.60%	2,560,738	24.10%	*12*
13	4,001-5,000	154	694,343	1,048	46.89%	2,389,986	11.25%	159	713,264	1,597	71.74%	3,274,002	30 81%	*13*
14	5,001-7,500	302	1,844,386	1,350	60.40%	4,234,372	19.94%	252	1,502,608	1,849	83.06%	4,776,610	44 95%	*14*
15	7,501-10,000	229	1,991,308	1,579	70.65%	6,225,680	29.31%	143	1,253,300	1,992	89.49%	6,029,910	56.75%	*15*
16	10,001-15,000	262	3,177,915	1,841	82.37%	9,403,595	44.28%	103	1,239,060	2,095	94.12%	7,268,970	68.41%	*16*
17	15,001-20,000	117	2,013,820	1,958	87.61%	11,417,415	53.76%	52	900,200	2,147	96.45%	8,169,170	76 88%	*17*
18	20,001-25,000	95	2,146,500	2,053	91.86%	13,563,915	63.87%	28	621,860	2,175	97.71%	8,791,030	82.73%	*18*
19	25,001-30,000	63	1,718,680	2,116	94.68%	15,282,595	71.96%	19	519,800	2,194	98.56%	9,310,830	87 62%	*19*
20	30,001-35,000	26	833,700	2,142	95.84%	16,116,295	75.89%	12	393,080	2,206	99.10%	9,703,910	91 32%	*20*
21	35,001-40,000	24	886,060	2,166	96.91%	17,002,355	80.06%	7	260,880	2,213	99.42%	9,964,790	93.78%	*21*
22	40,001-50,000	30	1,325,360	2,196	98.26%	18,327,715	86.30%	7	309,440	2,220	99.73%	10,274,230	96 69%	*22*
23	50,001-75,000	23	1,354,520	2,219	99.28%	19,682,235	92.68%	6	351,600	2,226	100.00%	10,625,830	100 00%	*23*
24	75,001-100,000	9	752,480	2,228	99.69%	20,434,715	96.22%	-	-	2,226	100.00%	10,625,830	100 00%	*24*
25	100,001-125,000	7	802,800	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*25*
26	125,001-150,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*26*
27	150,001-200,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*27*
28	200,001-300,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*28*
29	300,001-400,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*29*
30	400,001-500,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*30*
31	500,001-750,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*31*
32	750,001-1,000,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*32*
33	Over 1,000,000	-	-	2,235	100.00%	21,237,515	100.00%	-	-	2,226	100.00%	10,625,830	100 00%	*33*

Average Number of Customers:	373		Average Number of Customers:	371	
Average Consumption:	9,502	kWh per bill	Average Consumption:	4,774	kWh per bill
Median Consumption:	5,440	kWh per bill	Median Consumption:	2,880	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-30**
DESCR PTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	25	-	25	0.11%	-	0 00%	24	-	24	0.10%	-	0.00%	*1*
2	1-100	17,774	504,660	17,799	76.78%	504,660	21 60%	17,609	501,004	17,633	76 51%	501,004	21.44%	*2*
3	101-200	2,353	366,397	20,152	86 93%	871,057	37 29%	2,384	373,715	20,017	86 85%	874,719	37.44%	*3*
4	201-300	1,214	322,364	21,366	92.17%	1,193,421	51 09%	1,168	310,952	21,185	91 92%	1,185,671	50.75%	*4*
5	301-400	794	277,642	22,160	95 59%	1,471,063	62 97%	847	296,516	22,032	95 59%	1,482,187	63.44%	*5*
6	401-500	383	171,784	22,543	97 24%	1,642,847	70 33%	384	172,183	22,416	97.26%	1,654,370	70.81%	*6*
7	501-750	90	56,520	22,633	97 63%	1,699,367	72.75%	89	55,547	22,505	97.64%	1,709,917	73.19%	*7*
8	751-1,000	60	53,525	22,693	97 89%	1,752,892	75 04%	60	53,508	22,565	97 90%	1,763,425	75.48%	*8*
9	1,001-1,500	470	538,427	23,163	99 92%	2,291,319	98 09%	465	531,833	23,030	99 92%	2,295,258	98.25%	*9*
10	1,501-2,000	6	10,050	23,169	99 94%	2,301,369	98 52%	7	11,656	23,037	99.95%	2,306,914	98.74%	*10*
11	2,001-3,000	6	13,140	23,175	99 97%	2,314,509	99 08%	5	10,950	23,042	99.97%	2,317,864	99.21%	*11*
12	3,001-4,000	7	21,448	23,182	100.00%	2,335,957	100 00%	6	18,384	23,048	100.00%	2,336,248	100.00%	*12*
13	4,001-5,000	-	-	23,182	100.00%	2,335,957	100.00%	-	-	23,048	100.00%	2,336,248	100.00%	*13*
14	5,001-7,500	-	-	23,182	100.00%	2,335,957	100.00%	-	-	23,048	100.00%	2,336,248	100.00%	*14*
15	7,501-10,000	-	-	23,182	100.00%	2,335,957	100.00%	-	-	23,048	100.00%	2,336,248	100.00%	*15*
16	10,001-15,000	-	-	23,182	100.00%	2,335,957	100.00%	-	-	23,048	100.00%	2,336,248	100.00%	*16*
17	15,001-20,000	-	-	23,182	100.00%	2,335,957	100.00%	-	-	23,048	100.00%	2,336,248	100.00%	*17*
18	20,001-25,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*18*
19	25,001-30,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*19*
20	30,001-35,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*20*
21	35,001-40,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*21*
22	40,001-50,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*22*
23	50,001-75,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*23*
24	75,001-100,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*24*
25	100,001-125,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*25*
26	125,001-150,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*26*
27	150,001-200,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*27*
28	200,001-300,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*28*
29	300,001-400,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*29*
30	400,001-500,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*30*
31	500,001-750,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*31*
32	750,001-1,000,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*32*
33	Over 1,000,000	-	-	23,182	100 00%	2,335,957	100 00%	-	-	23,048	100 00%	2,336,248	100.00%	*33*

Average Number of Customers:	3,864		Average Number of Customers:	3,841	
Average Consumption:	101	kWh per bill	Average Consumption:	101	kWh per bill
Median Consumption:	37	kWh per bill	Median Consumption:	37	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Extra Small**
DESCR PTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	30,418	-	30,418	4.69%	-	0.00%	31,899	-	31,899	4.91%	-	0 00%	*1.*
2.	1-100	99,643	4,036,908	130,061	20.06%	4,036,908	0.42%	102,135	4,278,151	134,034	20.62%	4,278,151	0.60%	*2.*
3.	101-200	52,578	7,744,561	182,639	28.17%	11,781,469	1.23%	62,738	9,263,093	196,772	30.28%	13,541,244	1.91%	*3.*
4.	201-300	38,118	9,481,817	220,757	34.05%	21,263,286	2.22%	47,733	11,905,684	244,505	37.62%	25,446,928	3.60%	*4.*
5.	301-400	33,738	11,830,434	254,495	39.25%	33,093,720	3.45%	42,298	14,816,852	286,803	44.13%	40,263,780	5 69%	*5.*
6.	401-500	31,615	14,209,167	286,110	44.13%	47,302,887	4.94%	38,819	17,464,194	325,622	50.10%	57,727,974	8.16%	*6.*
7.	501-750	60,806	37,663,272	346,916	53.51%	84,966,159	8.87%	75,747	46,822,611	401,369	61.76%	104,550,585	14.77%	*7.*
8.	751-1,000	44,194	38,433,341	391,110	60.32%	123,399,500	12.88%	51,872	45,032,484	453,241	69.74%	149,583,069	21.13%	*8.*
9.	1,001-1,500	63,821	78,902,058	454,931	70.17%	202,301,558	21.12%	63,950	78,529,264	517,191	79.58%	228,112,333	32.23%	*9.*
10.	1,501-2,000	45,588	79,206,150	500,519	77.20%	281,507,708	29.38%	39,093	67,753,371	556,284	85.59%	295,865,704	41.80%	*10.*
11.	2,001-3,000	58,505	143,958,177	559,024	86.22%	425,465,885	44.41%	42,548	103,964,797	598,832	92.14%	399,830,501	56.49%	*11.*
12.	3,001-4,000	33,952	117,519,278	592,976	91.46%	542,985,163	56.68%	21,153	73,004,496	619,985	95.40%	472,834,997	66.80%	*12.*
13.	4,001-5,000	20,542	91,692,590	613,518	94.63%	634,677,753	66.25%	11,884	52,972,520	631,869	97.22%	525,807,517	74.28%	*13.*
14.	5,001-7,500	23,982	144,223,885	637,500	98.33%	778,901,638	81.30%	12,442	74,417,680	644,311	99.14%	600,225,197	84.80%	*14.*
15.	7,501-10,000	6,741	57,097,526	644,241	99.37%	835,999,164	87.26%	3,102	26,272,736	647,413	99.62%	626,497,933	88.51%	*15.*
16.	10,001-15,000	2,165	25,146,576	646,406	99.70%	861,145,740	89.89%	1,343	15,943,897	648,756	99.82%	642,441,830	90.76%	*16.*
17.	15,001-20,000	596	10,208,307	647,002	99.79%	871,354,047	90.95%	339	5,878,780	649,095	99.87%	648,320,610	91.59%	*17.*
18.	20,001-25,000	347	7,798,357	647,349	99.85%	879,152,404	91.77%	213	4,716,415	649,308	99.91%	653,037,025	92.26%	*18.*
19.	25,001-30,000	205	5,643,351	647,554	99.88%	884,795,755	92.35%	98	2,689,077	649,406	99.92%	655,726,102	92.64%	*19.*
20.	30,001-35,000	109	3,539,426	647,663	99.89%	888,335,181	92.72%	65	2,101,960	649,471	99.93%	657,828,062	92.94%	*20.*
21.	35,001-40,000	81	3,066,827	647,744	99.91%	891,402,008	93.04%	49	1,843,213	649,520	99.94%	659,671,275	93.20%	*21.*
22.	40,001-50,000	135	6,017,455	647,879	99.93%	897,419,463	93.67%	84	3,743,435	649,604	99.95%	663,414,710	93.73%	*22.*
23.	50,001-75,000	207	12,733,152	648,086	99.96%	910,152,615	95.00%	117	7,105,632	649,721	99.97%	670,520,342	94.73%	*23.*
24.	75,001-100,000	86	7,459,660	648,172	99.97%	917,612,275	95.78%	64	5,462,540	649,785	99.98%	675,982,882	95.50%	*24.*
25.	100,001-125,000	46	5,154,940	648,218	99.98%	922,767,215	96.32%	23	2,562,780	649,808	99.98%	678,545,662	95.86%	*25.*
26.	125,001-150,000	30	4,083,320	648,248	99.99%	926,850,535	96.74%	12	1,667,060	649,820	99.99%	680,212,722	96.10%	*26.*
27.	150,001-200,000	29	5,042,660	648,277	99.99%	931,893,195	97.27%	37	6,429,780	649,857	99.99%	686,642,502	97.01%	*27.*
28.	200,001-300,000	39	9,697,220	648,316	100.00%	941,590,415	98.28%	27	6,804,220	649,884	100.00%	693,446,722	97.97%	*28.*
29.	300,001-400,000	10	3,201,900	648,326	100.00%	944,792,315	98.62%	9	2,856,640	649,893	100.00%	696,303,362	98.37%	*29.*
30.	400,001-500,000	4	1,877,300	648,330	100.00%	946,669,615	98.81%	5	2,365,100	649,898	100.00%	698,668,462	98.71%	*30.*
31.	500,001-750,000	9	5,478,100	648,339	100.00%	952,147,715	99.38%	11	6,480,000	649,909	100.00%	705,148,462	99.62%	*31.*
32.	750,001-1,000,000	2	1,944,000	648,341	100.00%	954,091,715	99.59%	3	2,676,800	649,912	100.00%	707,825,262	100.00%	*32.*
33.	Over 1,000,000	3	3,955,200	648,344	100.00%	958,046,915	100.00%	-	-	649,912	100.00%	707,825,262	100.00%	*33.*

Average Number of Customers:	108,057		Average Number of Customers:	108,319	
Average Consumption:	1,478	kWh per bill	Average Consumption:	1,089	kWh per bill
Median Consumption:	648	kWh per bill	Median Consumption:	498	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Extra Small with Demand**
DESCR PTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	93	-	93	1.07%	-	0.00%	142	-	142	1.65%	-	0 00%	*1.*
2.	1-100	193	7,470	286	3.28%	7,470	0.03%	204	8,554	346	4.01%	8,554	0 04%	*2.*
3.	101-200	294	49,236	580	6.65%	56,706	0.26%	332	55,469	678	7.86%	64,023	0 32%	*3.*
4.	201-300	692	176,461	1,272	14.59%	233,167	1.05%	714	182,213	1,392	16.14%	246,236	1 23%	*4.*
5.	301-400	976	343,699	2,248	25.78%	576,866	2.61%	1,021	358,029	2,413	27.98%	604,265	3 02%	*5.*
6.	401-500	804	359,792	3,052	35.00%	936,658	4.23%	806	359,411	3,219	37.32%	963,676	4 82%	*6.*
7.	501-750	682	400,082	3,734	42.82%	1,336,740	6.04%	676	400,327	3,895	45.16%	1,364,003	6 82%	*7.*
8.	751-1,000	246	211,678	3,980	45.64%	1,548,418	7.00%	254	220,716	4,149	48.10%	1,584,719	7.92%	*8.*
9.	1,001-1,500	293	370,576	4,273	49.00%	1,918,994	8.67%	380	471,477	4,529	52.51%	2,056,196	10.28%	*9.*
10.	1,501-2,000	345	608,049	4,618	52.96%	2,527,043	11.42%	280	499,395	4,809	55.76%	2,555,591	12.77%	*10.*
11.	2,001-3,000	1,045	2,653,331	5,663	64.94%	5,180,374	23.41%	1,111	2,817,357	5,920	68.64%	5,372,948	26.85%	*11.*
12.	3,001-4,000	878	3,071,207	6,541	75.01%	8,251,581	37.28%	877	3,022,482	6,797	78.81%	8,395,430	41.96%	*12.*
13.	4,001-5,000	635	2,848,947	7,176	82.29%	11,100,528	50.16%	539	2,399,858	7,336	85.06%	10,795,288	53.95%	*13.*
14.	5,001-7,500	1,049	6,609,327	8,225	94.32%	17,709,855	80.02%	876	5,632,461	8,212	95.21%	16,427,749	82.10%	*14.*
15.	7,501-10,000	433	3,641,138	8,658	99.29%	21,350,993	96.47%	379	3,152,664	8,591	99.61%	19,580,413	97.86%	*15.*
16.	10,001-15,000	56	622,586	8,714	99.93%	21,973,579	99.28%	32	350,922	8,623	99.98%	19,931,335	99.61%	*16.*
17.	15,001-20,000	2	35,000	8,716	99.95%	22,008,579	99.44%	-	-	8,623	99.98%	19,931,335	99.61%	*17.*
18.	20,001-25,000	2	43,840	8,718	99.98%	22,052,419	99.64%	-	-	8,623	99.98%	19,931,335	99.61%	*18.*
19.	25,001-30,000	-	-	8,718	99.98%	22,052,419	99.64%	-	-	8,623	99.98%	19,931,335	99 61%	*19.*
20.	30,001-35,000	-	-	8,718	99.98%	22,052,419	99.64%	-	-	8,623	99.98%	19,931,335	99 61%	*20.*
21.	35,001-40,000	1	37,144	8,719	99.99%	22,089,563	99.81%	2	77,038	8,625	100.00%	20,008,373	100 00%	*21.*
22.	40,001-50,000	1	42,395	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*22.*
23.	50,001-75,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*23.*
24.	75,001-100,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*24.*
25.	100,001-125,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*25.*
26.	125,001-150,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*26.*
27.	150,001-200,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100.00%	*27.*
28.	200,001-300,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100.00%	*28.*
29.	300,001-400,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*29.*
30.	400,001-500,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*30.*
31.	500,001-750,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*31.*
32.	750,001-1,000,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*32.*
33.	Over 1,000,000	-	-	8,720	100.00%	22,131,958	100.00%	-	-	8,625	100.00%	20,008,373	100 00%	*33.*

Average Number of Customers:	1,453		Average Number of Customers:	1,438	
Average Consumption:	2,538	kWh per bill	Average Consumption:	2,320	kWh per bill
Median Consumption:	1,637	kWh per bill	Median Consumption:	1,200	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Small**
DESCR PTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	1,391	-	1,391	1.22%	-	0.00%	1,360	-	1,360	1.18%	-	0.00%	*1*
2	1-100	286	14,473	1,677	1.47%	14,473	0.00%	386	20,201	1,746	1.51%	20,201	0.00%	*2*
3	101-200	272	41,215	1,949	1.71%	55,688	0.00%	314	45,897	2,060	1.78%	66,098	0 01%	*3*
4	201-300	195	47,754	2,144	1.88%	103,442	0.01%	257	64,307	2,317	2.01%	130,405	0 01%	*4*
5	301-400	187	65,949	2,331	2.04%	169,391	0.01%	363	129,709	2,680	2.32%	260,114	0 02%	*5*
6	401-500	194	89,500	2,525	2.21%	258,891	0.02%	363	166,524	3,043	2.63%	426,638	0 04%	*6*
7	501-750	474	296,782	2,999	2.63%	555,673	0.04%	1,072	675,784	4,115	3.56%	1,102,422	0.10%	*7*
8	751-1,000	516	453,078	3,515	3.08%	1,008,751	0.07%	1,227	1,083,595	5,342	4.62%	2,186,017	0.20%	*8*
9	1,001-1,500	1,134	1,429,524	4,649	4.08%	2,438,275	0.16%	2,878	3,632,389	8,220	7.12%	5,818,406	0.54%	*9*
10	1,501-2,000	1,413	2,488,223	6,062	5.31%	4,926,498	0.33%	3,799	6,693,571	12,019	10.41%	12,511,977	1.16%	*10*
11	2,001-3,000	3,736	9,528,082	9,798	8.59%	14,454,580	0.96%	9,597	24,210,529	21,616	18.71%	36,722,506	3.41%	*11*
12	3,001-4,000	5,228	18,452,675	15,026	13.17%	32,907,255	2.19%	10,707	37,706,242	32,323	27.98%	74,428,748	6.92%	*12*
13	4,001-5,000	6,289	28,426,935	21,315	18.69%	61,334,190	4.09%	10,694	48,203,424	43,017	37.24%	122,632,172	11.39%	*13*
14	5,001-7,500	18,025	113,090,779	39,340	34.49%	174,424,969	11.62%	21,538	132,809,157	64,555	55.89%	255,441,329	23.73%	*14*
15	7,501-10,000	17,483	152,505,420	56,823	49.82%	326,930,389	21.78%	14,153	122,894,155	78,708	68.14%	378,335,484	35.15%	*15*
16	10,001-15,000	22,637	277,475,740	79,460	69.66%	604,406,129	40.26%	16,634	203,773,653	95,342	82.54%	582,109,137	54.08%	*16*
17	15,001-20,000	12,576	217,911,042	92,036	80.69%	822,317,171	54.78%	9,425	163,178,604	104,767	90.70%	745,287,741	69.24%	*17*
18	20,001-25,000	8,015	179,080,961	100,051	87.72%	1,001,398,132	66.71%	4,952	110,276,935	109,719	94.99%	855,564,676	79.49%	*18*
19	25,001-30,000	5,281	144,508,097	105,332	92.35%	1,145,906,229	76.33%	2,533	68,939,767	112,252	97.18%	924,504,443	85.89%	*19*
20	30,001-35,000	3,524	114,020,141	108,856	95.44%	1,259,926,370	83.93%	1,342	43,246,519	113,594	98.34%	967,750,962	89.91%	*20*
21	35,001-40,000	2,222	82,915,673	111,078	97.38%	1,342,842,043	89.45%	775	28,874,709	114,369	99.01%	996,625,671	92.60%	*21*
22	40,001-50,000	2,132	93,837,261	113,210	99.25%	1,436,679,304	95.70%	640	28,043,208	115,009	99.57%	1,024,668,879	95.20%	*22*
23	50,001-75,000	681	38,663,368	113,891	99.85%	1,475,342,672	98.28%	334	19,540,893	115,343	99.86%	1,044,209,772	97.02%	*23*
24	75,001-100,000	82	6,900,363	113,973	99.92%	1,482,243,035	98.74%	51	4,342,420	115,394	99.90%	1,048,552,192	97.42%	*24*
25	100,001-125,000	30	3,320,980	114,003	99.95%	1,485,564,015	98.96%	22	2,456,380	115,416	99.92%	1,051,008,572	97.65%	*25*
26	125,001-150,000	24	3,323,400	114,027	99.97%	1,488,887,415	99.18%	20	2,754,200	115,436	99.94%	1,053,762,772	97.90%	*26*
27	150,001-200,000	14	2,365,460	114,041	99.98%	1,491,252,875	99.34%	18	3,076,180	115,454	99.95%	1,056,838,952	98.19%	*27*
28	200,001-300,000	5	1,231,000	114,046	99.99%	1,492,483,875	99.42%	24	5,601,200	115,478	99.97%	1,062,440,152	98.71%	*28*
29	300,001-400,000	2	752,800	114,048	99.99%	1,493,236,675	99.47%	11	3,874,800	115,489	99.98%	1,066,314,952	99.07%	*29*
30	400,001-500,000	7	3,228,400	114,055	99.99%	1,496,465,075	99.69%	8	3,533,300	115,497	99.99%	1,069,848,252	99.40%	*30*
31	500,001-750,000	4	2,750,200	114,059	100.00%	1,499,215,275	99.87%	8	4,723,600	115,505	100.00%	1,074,571,852	99.84%	*31*
32	750,001-1,000,000	1	750,600	114,060	100.00%	1,499,965,875	99.92%	2	1,747,600	115,507	100.00%	1,076,319,452	100.00%	*32*
33	Over 1,000,000	1	1,224,000	114,061	100.00%	1,501,189,875	100.00%	-	-	115,507	100.00%	1,076,319,452	100.00%	*33*

Average Number of	19,010		Average Number of	19,251	
Average Consumpti	13,161	kWh per bill	Average Consumpti	9,318	kWh per bill
Median Consumptio	10,066	kWh per bill	Median Consumptio	6,600	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Medium (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1	0	433	-	433	1.68%	-	0 00%	443	-	443	1.69%	-	0 00%	*1*
2	1-100	6	372	439	1.70%	372	0 00%	8	510	451	1.72%	510	0 00%	*2*
3	101-200	12	1,732	451	1.75%	2,104	0 00%	25	3,283	476	1.81%	3,793	0 00%	*3*
4	201-300	8	1,920	459	1.78%	4,024	0 00%	24	5,862	500	1.90%	9,655	0 00%	*4*
5	301-400	16	5,910	475	1.84%	9,934	0 00%	26	9,560	526	2.00%	19,215	0 00%	*5*
6	401-500	10	4,800	485	1.88%	14,734	0 00%	19	9,080	545	2.07%	28,295	0 00%	*6*
7	501-750	29	18,975	514	2.00%	33,709	0 00%	29	18,181	574	2.18%	46,476	0 00%	*7*
8	751-1,000	25	21,274	539	2.09%	54,983	0 00%	42	36,646	616	2.34%	83,122	0 01%	*8*
9	1,001-1,500	19	24,420	558	2.17%	79,403	0 00%	50	63,479	666	2.53%	146,601	0 01%	*9*
10	1,501-2,000	36	63,129	594	2.31%	142,532	0 01%	47	82,697	713	2.71%	229,298	0 02%	*10*
11	2,001-3,000	63	159,826	657	2.55%	302,358	0 02%	121	300,471	834	3.17%	529,769	0 04%	*11*
12	3,001-4,000	75	258,276	732	2.84%	560,634	0 03%	107	377,650	941	3.58%	907,419	0 06%	*12*
13	4,001-5,000	64	289,110	796	3.09%	849,744	0 05%	110	497,600	1,051	4.00%	1,405,019	0.10%	*13*
14	5,001-7,500	165	1,032,251	961	3.73%	1,881,995	0.10%	314	1,992,516	1,365	5.19%	3,397,535	0 23%	*14*
15	7,501-10,000	186	1,651,196	1,147	4.45%	3,533,191	0.19%	387	3,407,071	1,752	6.67%	6,804,606	0.47%	*15*
16	10,001-15,000	453	5,787,314	1,600	6.21%	9,320,505	0 50%	1,082	13,860,872	2,834	10.78%	20,665,478	1.42%	*16*
17	15,001-20,000	597	10,502,753	2,197	8.53%	19,823,258	1 07%	1,526	26,830,096	4,360	16.59%	47,495,574	3 27%	*17*
18	20,001-25,000	804	18,123,180	3,001	11.65%	37,946,438	2 06%	1,800	40,752,971	6,160	23.44%	88,248,545	6 07%	*18*
19	25,001-30,000	997	27,583,298	3,998	15.52%	65,529,736	3 55%	2,016	55,641,451	8,176	31.11%	143,889,996	9 90%	*19*
20	30,001-35,000	1,200	39,107,833	5,198	20.18%	104,637,569	5 67%	2,017	65,663,151	10,193	38.78%	209,553,147	14.42%	*20*
21	35,001-40,000	1,481	55,552,652	6,679	25.93%	160,190,221	8 68%	1,923	72,137,336	12,116	46.10%	281,690,483	19 38%	*21*
22	40,001-50,000	3,233	145,824,985	9,912	38.49%	306,015,206	16 58%	3,328	149,193,223	15,444	58.76%	430,883,706	29 65%	*22*
23	50,001-75,000	6,603	406,178,523	16,515	64.13%	712,193,729	38 59%	5,064	308,038,162	20,508	78.02%	738,921,868	50 85%	*23*
24	75,001-100,000	3,780	326,159,212	20,295	78.80%	1,038,352,941	56 26%	2,495	215,598,925	23,003	87.52%	954,520,793	65 69%	*24*
25	100,001-125,000	2,146	239,036,107	22,441	87.14%	1,277,389,048	69 21%	1,349	150,103,601	24,352	92.65%	1,104,624,394	76 01%	*25*
26	125,001-150,000	1,326	181,416,771	23,767	92.28%	1,458,805,819	79 04%	825	112,522,665	25,177	95.79%	1,217,147,059	83.76%	*26*
27	150,001-200,000	1,449	248,711,859	25,216	97.91%	1,707,517,678	92 51%	797	135,039,600	25,974	98.82%	1,352,186,659	93 05%	*27*
28	200,001-300,000	494	112,747,538	25,710	99.83%	1,820,265,216	98 62%	215	49,623,140	26,189	99.64%	1,401,809,799	96.47%	*28*
29	300,001-400,000	24	7,897,260	25,734	99.92%	1,828,162,476	99 05%	28	9,457,040	26,217	99.75%	1,411,266,839	97.12%	*29*
30	400,001-500,000	5	2,219,800	25,739	99.94%	1,830,382,276	99.17%	22	9,722,100	26,239	99.83%	1,420,988,939	97.79%	*30*
31	500,001-750,000	8	4,907,500	25,747	99.97%	1,835,289,776	99.43%	35	20,943,800	26,274	99.96%	1,441,932,739	99 23%	*31*
32	750,001-1,000,000	2	1,746,800	25,749	99.98%	1,837,036,576	99 53%	3	2,460,200	26,277	99.97%	1,444,392,939	99.40%	*32*
33	Over 1,000,000	5	8,719,200	25,754	100.00%	1,845,755,776	100 00%	7	8,781,000	26,284	100.00%	1,453,173,939	100 00%	*33*

Average Number of	4,292			Average Number of	4,381	
Average Consumpti	71,669	kWh per bill		Average Consumpti	55,287	kWh per bill
Median Consumptio	59,840	kWh per bill		Median Consumptio	42,880	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Large (excludes AG-1)**
DESCR PTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						W NTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	34	-	34	0.74%	-	0 00%	32	-	32	0.67%	-	0 00%	1.
2.	1-100	-	-	34	0.74%	-	0 00%	1	72	33	0.69%	72	0 00%	2.
3.	101-200	1	120	35	0.76%	120	0 00%	-	-	33	0.69%	72	0 00%	3.
4.	201-300	2	511	37	0.80%	631	0 00%	-	-	33	0.69%	72	0 00%	4.
5.	301-400	-	-	37	0.80%	631	0 00%	1	400	34	0.71%	472	0 00%	5.
6.	401-500	-	-	37	0.80%	631	0 00%	-	-	34	0.71%	472	0 00%	6.
7.	501-750	-	-	37	0.80%	631	0 00%	-	-	34	0.71%	472	0 00%	7.
8.	751-1,000	3	2,900	40	0.87%	3,531	0 00%	-	-	34	0.71%	472	0 00%	8.
9.	1,001-1,500	-	-	40	0.87%	3,531	0 00%	1	1,200	35	0.73%	1,672	0 00%	9.
10.	1,501-2,000	4	7,600	44	0.95%	11,131	0 00%	2	4,000	37	0.77%	5,672	0 00%	10.
11.	2,001-3,000	2	5,700	46	1.00%	16,831	0 00%	1	2,800	38	0.80%	8,472	0 00%	11.
12.	3,001-4,000	-	-	46	1.00%	16,831	0 00%	1	4,000	39	0.82%	12,472	0 00%	12.
13.	4,001-5,000	3	12,725	49	1.06%	29,556	0 00%	5	22,174	44	0.92%	34,646	0 00%	13.
14.	5,001-7,500	4	23,385	53	1.15%	52,941	0 00%	4	23,660	48	1.00%	58,306	0 00%	14.
15.	7,501-10,000	11	96,080	64	1.38%	149,021	0 01%	11	98,665	59	1.24%	156,971	0 01%	15.
16.	10,001-15,000	14	180,459	78	1.69%	329,480	0 02%	11	134,524	70	1.47%	291,495	0 02%	16.
17.	15,001-20,000	16	294,292	94	2 03%	623,772	0 04%	19	328,741	89	1.86%	620,236	0 05%	17.
18.	20,001-25,000	18	402,010	112	2.42%	1,025,782	0 07%	12	266,319	101	2.11%	886,555	0 07%	18.
19.	25,001-30,000	9	248,820	121	2.62%	1,274,602	0 08%	24	664,880	125	2.62%	1,551,435	0.12%	19.
20.	30,001-35,000	11	360,500	132	2.86%	1,635,102	0.11%	21	675,200	146	3.06%	2,226,635	0.17%	20.
21.	35,001-40,000	24	898,480	156	3.38%	2,533,582	0.16%	27	1,024,440	173	3.62%	3,251,075	0 25%	21.
22.	40,001-50,000	34	1,537,254	190	4.11%	4,070,836	0 26%	56	2,525,220	229	4.79%	5,776,295	0.44%	22.
23.	50,001-75,000	103	6,517,986	293	6 34%	10,588,822	0 68%	170	10,745,603	399	8.35%	16,521,898	1 27%	23.
24.	75,001-100,000	122	10,829,463	415	8 98%	21,418,285	1 38%	246	21,555,940	645	13.50%	38,077,838	2 92%	24.
25.	100,001-125,000	135	15,280,740	550	11 90%	36,699,025	2 37%	361	40,947,040	1,006	21.06%	79,024,878	6 06%	25.
26.	125,001-150,000	241	33,314,520	791	17.11%	70,013,545	4 52%	428	58,811,280	1,434	30.02%	137,836,158	10 58%	26.
27.	150,001-200,000	648	113,325,656	1,439	31.13%	183,339,201	11 83%	782	136,308,192	2,216	46.39%	274,144,350	21 04%	27.
28.	200,001-300,000	1,283	318,680,068	2,722	58.89%	502,019,269	32.41%	1,214	297,960,709	3,430	71.80%	572,105,059	43 90%	28.
29.	300,001-400,000	759	260,907,376	3,481	75.31%	762,926,645	49 25%	503	172,120,760	3,933	82.33%	744,225,819	57.11%	29.
30.	400,001-500,000	368	164,555,920	3,849	83.28%	927,482,565	59 87%	261	116,995,860	4,194	87.80%	861,221,679	66 09%	30.
31.	500,001-750,000	458	278,640,663	4,307	93.18%	1,206,123,228	77 86%	386	232,400,300	4,580	95.88%	1,093,621,979	83 93%	31.
32.	750,001-1,000,000	173	146,716,336	4,480	96.93%	1,352,839,564	87 33%	99	83,377,400	4,679	97.95%	1,176,999,379	90 32%	32.
33.	Over 1,000,000	142	196,350,338	4,622	100.00%	1,549,189,902	100 00%	98	126,094,600	4,777	100.00%	1,303,093,979	100 00%	33.

Average Number of Customers:	770		Average Number of Customers:	796	
Average Consumption:	335,177	kWh per bill	Average Consumption:	272,785	kWh per bill
Median Consumption:	265,200	kWh per bill	Median Consumption:	212,280	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Extra Small GS TOU**
DESCR PTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	67	-	67	1.67%	-	0.00%	75	-	75	1.86%	-	0.00%	*1.*
2.	1-100	89	4,196	156	3.90%	4,196	0.04%	95	4,875	170	4.21%	4,875	0.05%	*2.*
3.	101-200	79	11,906	235	5.87%	16,102	0.14%	91	13,239	261	6.47%	18,114	0.18%	*3.*
4.	201-300	143	36,931	378	9.44%	53,033	0.45%	147	38,495	408	10.11%	56,609	0.55%	*4.*
5.	301-400	277	96,991	655	16.36%	150,024	1.28%	295	103,754	703	17.42%	160,363	1.56%	*5.*
6.	401-500	456	209,146	1,111	27.75%	359,170	3.07%	526	240,436	1,229	30.45%	400,799	3.90%	*6.*
7.	501-750	619	359,488	1,730	43.21%	718,658	6.14%	554	322,851	1,783	44.18%	723,650	7 05%	*7.*
8.	751-1,000	112	92,644	1,842	46.00%	811,302	6.93%	100	83,804	1,883	46.66%	807,454	7.86%	*8.*
9.	1,001-1,500	58	71,596	1,900	47.45%	882,898	7.54%	77	97,784	1,960	48.56%	905,238	8.81%	*9.*
10.	1,501-2,000	58	102,628	1,958	48.90%	985,526	8.42%	78	136,728	2,038	50.50%	1,041,966	10.14%	*10.*
11.	2,001-3,000	241	623,262	2,199	54.92%	1,608,788	13.74%	279	719,679	2,317	57.41%	1,761,645	17.15%	*11.*
12.	3,001-4,000	390	1,380,449	2,589	64.66%	2,989,237	25.52%	551	1,949,133	2,868	71.06%	3,710,778	36.13%	*12.*
13.	4,001-5,000	572	2,579,634	3,161	78.95%	5,568,871	47.55%	588	2,625,367	3,456	85.63%	6,336,145	61.69%	*13.*
14.	5,001-7,500	710	4,147,485	3,871	96.68%	9,716,356	82.96%	520	2,988,707	3,976	98.51%	9,324,852	90.78%	*14.*
15.	7,501-10,000	79	654,030	3,950	98.65%	10,370,386	88.55%	22	181,188	3,998	99.06%	9,506,040	92 55%	*15.*
16.	10,001-15,000	20	245,435	3,970	99.15%	10,615,821	90.64%	16	184,354	4,014	99.45%	9,690,394	94 34%	*16.*
17.	15,001-20,000	11	192,065	3,981	99.43%	10,807,886	92.28%	5	84,960	4,019	99.58%	9,775,354	95.17%	*17.*
18.	20,001-25,000	5	110,280	3,986	99.55%	10,918,166	93.23%	7	161,340	4,026	99.75%	9,936,694	96.74%	*18.*
19.	25,001-30,000	3	80,160	3,989	99.63%	10,998,326	93.91%	5	141,960	4,031	99.88%	10,078,654	98.12%	*19.*
20.	30,001-35,000	3	99,000	3,992	99.70%	11,097,326	94.76%	1	33,360	4,032	99.90%	10,112,014	98.45%	*20.*
21.	35,001-40,000	1	38,800	3,993	99.73%	11,136,126	95.09%	3	114,840	4,035	99.98%	10,226,854	99 56%	*21.*
22.	40,001-50,000	7	305,200	4,000	99.90%	11,441,326	97.69%	1	44,800	4,036	100.00%	10,271,654	100 00%	*22.*
23.	50,001-75,000	4	270,120	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*23.*
24.	75,001-100,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*24.*
25.	100,001-125,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*25.*
26.	125,001-150,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*26.*
27.	150,001-200,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100.00%	*27.*
28.	200,001-300,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100.00%	*28.*
29.	300,001-400,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*29.*
30.	400,001-500,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*30.*
31.	500,001-750,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*31.*
32.	750,001-1,000,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*32.*
33.	Over 1,000,000	-	-	4,004	100.00%	11,711,446	100.00%	-	-	4,036	100.00%	10,271,654	100 00%	*33.*

Average Number of Customers:	667		Average Number of Customers:	673	
Average Consumption:	2,925	kWh per bill	Average Consumption:	2,545	kWh per bill
Median Consumption:	2,244	kWh per bill	Median Consumption:	1,874	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32TOU SMALL**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	7	-	7	0.74%	-	0.00%	3	-	3	0.32%	-	0 00%	*1.*
2.	1-100	2	40	9	0.95%	40	0.00%	6	115	9	0.96%	115	0 00%	*2.*
3.	101-200	3	384	12	1.27%	424	0.00%	2	312	11	1.17%	427	0 00%	*3.*
4.	201-300	-	-	12	1.27%	424	0.00%	2	425	13	1.38%	852	0 01%	*4.*
5.	301-400	1	385	13	1.38%	809	0.00%	1	400	14	1.49%	1,252	0 01%	*5.*
6.	401-500	1	480	14	1.48%	1,289	0.01%	3	1,382	17	1.81%	2,634	0 02%	*6.*
7.	501-750	2	1,037	16	1.69%	2,326	0.01%	3	1,693	20	2.13%	4,327	0 03%	*7.*
8.	751-1,000	2	1,690	18	1.90%	4,016	0.02%	9	7,918	29	3.09%	12,245	0 09%	*8.*
9.	1,001-1,500	6	7,741	24	2.54%	11,757	0.06%	10	12,292	39	4.15%	24,537	0.18%	*9.*
10.	1,501-2,000	3	4,801	27	2.86%	16,558	0.09%	10	17,377	49	5.22%	41,914	0 31%	*10.*
11.	2,001-3,000	15	35,757	42	4.44%	52,315	0.29%	34	89,054	83	8.84%	130,968	0 97%	*11.*
12.	3,001-4,000	23	83,973	65	6.88%	136,288	0.75%	40	141,979	123	13.10%	272,947	2 02%	*12.*
13.	4,001-5,000	18	79,020	83	8.78%	215,308	1.18%	40	179,431	163	17.36%	452,378	3 34%	*13.*
14.	5,001-7,500	75	476,705	158	16.72%	692,013	3.79%	93	582,611	256	27.26%	1,034,989	7 65%	*14.*
15.	7,501-10,000	121	1,061,596	279	29.52%	1,753,609	9.61%	160	1,401,132	416	44.30%	2,436,121	18 00%	*15.*
16.	10,001-15,000	182	2,277,097	461	48.78%	4,030,706	22.09%	205	2,540,335	621	66.13%	4,976,456	36.76%	*16.*
17.	15,001-20,000	145	2,499,696	606	64.13%	6,530,402	35.79%	127	2,185,055	748	79.66%	7,161,511	52 91%	*17.*
18.	20,001-25,000	102	2,269,949	708	74.92%	8,800,351	48.24%	79	1,770,797	827	88.07%	8,932,308	65 99%	*18.*
19.	25,001-30,000	65	1,808,051	773	81.80%	10,608,402	58.15%	37	1,006,960	864	92.01%	9,939,268	73.43%	*19.*
20.	30,001-35,000	63	2,037,008	836	88.47%	12,645,410	69.31%	20	650,560	884	94.14%	10,589,828	78 23%	*20.*
21.	35,001-40,000	34	1,260,960	870	92.06%	13,906,370	76.22%	30	1,136,720	914	97.34%	11,726,548	86 63%	*21.*
22.	40,001-50,000	42	1,868,960	912	96.51%	15,775,330	86.47%	17	739,840	931	99.15%	12,466,388	92.10%	*22.*
23.	50,001-75,000	25	1,410,980	937	99.15%	17,186,310	94.20%	-	-	931	99.15%	12,466,388	92.10%	*23.*
24.	75,001-100,000	1	96,100	938	99.26%	17,282,410	94.73%	-	-	931	99.15%	12,466,388	92.10%	*24.*
25.	100,001-125,000	1	107,800	939	99.37%	17,390,210	95.32%	2	222,000	933	99.36%	12,688,388	93.74%	*25.*
26.	125,001-150,000	5	700,000	944	99.89%	18,090,210	99.15%	5	691,600	938	99.89%	13,379,988	98 85%	*26.*
27.	150,001-200,000	1	154,400	945	100.00%	18,244,610	100.00%	1	156,000	939	100.00%	13,535,988	100 00%	*27.*
28.	200,001-300,000	-	-	945	100.00%	18,244,610	100.00%	-	-	939	100.00%	13,535,988	100 00%	*28.*
29.	300,001-400,000	-	-	945	100.00%	18,244,610	100.00%	-	-	939	100.00%	13,535,988	100 00%	*29.*
30.	400,001-500,000	-	-	945	100.00%	18,244,610	100.00%	-	-	939	100.00%	13,535,988	100 00%	*30.*
31.	500,001-750,000	-	-	945	100.00%	18,244,610	100.00%	-	-	939	100.00%	13,535,988	100 00%	*31.*
32.	750,001-1,000,000	-	-	945	100.00%	18,244,610	100.00%	-	-	939	100.00%	13,535,988	100 00%	*32.*
33.	Over 1,000,000	-	-	945	100.00%	18,244,610	100.00%	-	-	939	100.00%	13,535,988	100 00%	*33.*

Average Number of Customers:	158		Average Number of Customers:	157	
Average Consumption:	19,306	kWh per bill	Average Consumption:	14,415	
Median Consumption:	15,200	kWh per bill	Median Consumption:	11,325	

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 TOU Medium**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	1	-	1	0.17%	-	0.00%	1	-	1	0.17%	-	0 00%	1.
2.	1-100	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	2.
3.	101-200	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	3.
4.	201-300	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	4.
5.	301-400	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	5.
6.	401-500	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	6.
7.	501-750	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	7.
8.	751-1,000	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	8.
9.	1,001-1,500	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	9.
10.	1,501-2,000	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	10.
11.	2,001-3,000	-	-	1	0.17%	-	0.00%	-	-	1	0.17%	-	0 00%	11.
12.	3,001-4,000	-	-	1	0.17%	-	0.00%	1	3,120	2	0.35%	3,120	0 01%	12.
13.	4,001-5,000	-	-	1	0.17%	-	0.00%	1	4,560	3	0.52%	7,680	0 02%	13.
14.	5,001-7,500	3	18,800	4	0 69%	18,800	0.03%	4	22,960	7	1.22%	30,640	0 07%	14.
15.	7,501-10,000	1	9,440	5	0 86%	28,240	0.05%	2	16,520	9	1.56%	47,160	0.11%	15.
16.	10,001-15,000	4	50,540	9	1 54%	78,780	0.14%	3	32,680	12	2.08%	79,840	0.18%	16.
17.	15,001-20,000	6	104,640	15	2 57%	183,420	0.32%	18	318,260	30	5.21%	398,100	0 89%	17.
18.	20,001-25,000	9	209,060	24	4.12%	392,480	0.69%	40	911,720	70	12.15%	1,309,820	2 92%	18.
19.	25,001-30,000	17	477,280	41	7.03%	869,760	1.53%	20	549,800	90	15.63%	1,859,620	4.14%	19.
20.	30,001-35,000	15	488,240	56	9.61%	1,358,000	2.39%	26	851,820	116	20.14%	2,711,440	6 04%	20.
21.	35,001-40,000	11	415,100	67	11.49%	1,773,100	3.12%	26	974,160	142	24.65%	3,685,600	8 21%	21.
22.	40,001-50,000	45	2,005,700	112	19.21%	3,778,800	6.65%	30	1,352,720	172	29.86%	5,038,320	11 23%	22.
23.	50,001-75,000	106	6,708,456	218	37.39%	10,487,256	18.45%	149	9,504,536	321	55.73%	14,542,856	32.41%	23.
24.	75,001-100,000	126	11,098,940	344	59.01%	21,586,196	37.98%	102	8,931,100	423	73.44%	23,473,956	52 31%	24.
25.	100,001-125,000	87	9,621,430	431	73.93%	31,207,626	54.91%	66	7,327,700	489	84.90%	30,801,656	68 64%	25.
26.	125,001-150,000	51	6,936,103	482	82.68%	38,143,729	67.12%	32	4,407,480	521	90.45%	35,209,136	78.47%	26.
27.	150,001-200,000	79	13,639,855	561	96.23%	51,783,584	91.12%	51	8,573,500	572	99.31%	43,782,636	97 57%	27.
28.	200,001-300,000	21	4,594,400	582	99.83%	56,377,984	99.20%	3	764,996	575	99.83%	44,547,632	99 28%	28.
29.	300,001-400,000	-	-	582	99.83%	56,377,984	99.20%	1	323,700	576	100.00%	44,871,332	100 00%	29.
30.	400,001-500,000	1	454,470	583	100.00%	56,832,454	100.00%	-	-	576	100.00%	44,871,332	100 00%	30.
31.	500,001-750,000	-	-	583	100.00%	56,832,454	100.00%	-	-	576	100.00%	44,871,332	100 00%	31.
32.	750,001-1,000,000	-	-	583	100.00%	56,832,454	100.00%	-	-	576	100.00%	44,871,332	100 00%	32.
33.	Over 1,000,000	-	-	583	100.00%	56,832,454	100.00%	-	-	576	100.00%	44,871,332	100 00%	33.

Average Number of Customers:	97		Average Number of Customers:	96	
Average Consumption:	97,483	kWh per bill	Average Consumption:	77,902	kWh per bill
Median Consumption:	90,400	kWh per bill	Median Consumption:	70,760	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 TOU Large (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	1	-	1	0.27%	-	0.00%	1	-	1	0.26%	-	0.00%	1.
2.	1-100	-	-	1	0.27%	-	0.00%	-	-	1	0.26%	-	0.00%	2.
3.	101-200	-	-	1	0.27%	-	0.00%	-	-	1	0.26%	-	0.00%	3.
4.	201-300	-	-	1	0.27%	-	0.00%	-	-	1	0.26%	-	0.00%	4.
5.	301-400	-	-	1	0.27%	-	0.00%	-	-	1	0.26%	-	0.00%	5.
6.	401-500	-	-	1	0.27%	-	0.00%	-	-	1	0.26%	-	0.00%	6.
7.	501-750	-	-	1	0.27%	-	0.00%	1	600	2	0.51%	600	0.00%	7.
8.	751-1,000	-	-	1	0.27%	-	0.00%	-	-	2	0.51%	600	0.00%	8.
9.	1,001-1,500	-	-	1	0.27%	-	0.00%	-	-	2	0.51%	600	0.00%	9.
10.	1,501-2,000	-	-	1	0.27%	-	0.00%	-	-	2	0.51%	600	0.00%	10.
11.	2,001-3,000	-	-	1	0.27%	-	0.00%	-	-	2	0.51%	600	0.00%	11.
12.	3,001-4,000	-	-	1	0.27%	-	0.00%	1	3,840	3	0.77%	4,440	0.00%	12.
13.	4,001-5,000	-	-	1	0.27%	-	0.00%	2	8,760	5	1.28%	13,200	0.01%	13.
14.	5,001-7,500	-	-	1	0.27%	-	0.00%	-	-	5	1.28%	13,200	0.01%	14.
15.	7,501-10,000	-	-	1	0.27%	-	0.00%	1	8,800	6	1.54%	22,000	0.02%	15.
16.	10,001-15,000	-	-	1	0.27%	-	0.00%	-	-	6	1.54%	22,000	0.02%	16.
17.	15,001-20,000	-	-	1	0.27%	-	0.00%	-	-	6	1.54%	22,000	0.02%	17.
18.	20,001-25,000	-	-	1	0.27%	-	0.00%	1	22,000	7	1.79%	44,000	0.03%	18.
19.	25,001-30,000	-	-	1	0.27%	-	0.00%	2	54,960	9	2.31%	98,960	0.07%	19.
20.	30,001-35,000	-	-	1	0.27%	-	0.00%	1	34,560	10	2.56%	133,520	0.10%	20.
21.	35,001-40,000	1	40,000	2	0.53%	40,000	0.02%	-	-	10	2.56%	133,520	0.10%	21.
22.	40,001-50,000	2	98,600	4	1.07%	138,600	0.09%	5	225,200	15	3.85%	358,720	0.26%	22.
23.	50,001-75,000	12	696,760	16	4.28%	835,360	0.51%	21	1,326,420	36	9.23%	1,685,140	1.23%	23.
24.	75,001-100,000	3	257,500	19	5.08%	1,092,860	0.67%	24	2,127,260	60	15.38%	3,812,400	2.79%	24.
25.	100,001-125,000	16	1,831,240	35	9.36%	2,924,100	1.80%	27	3,025,281	87	22.31%	6,837,681	5.00%	25.
26.	125,001-150,000	23	3,145,305	58	15.51%	6,069,405	3.74%	23	3,159,280	110	28.21%	9,996,961	7.32%	26.
27.	150,001-200,000	40	6,957,713	98	26.20%	13,027,118	8.02%	43	7,613,128	153	39.23%	17,610,089	12.89%	27.
28.	200,001-300,000	87	21,075,247	185	49.47%	34,102,365	21.00%	84	20,026,141	237	60.77%	37,636,230	27.54%	28.
29.	300,001-400,000	50	17,359,569	235	62.83%	51,461,934	31.68%	43	14,400,766	280	71.79%	52,036,996	38.08%	29.
30.	400,001-500,000	31	13,959,620	266	71.12%	65,421,554	40.28%	30	13,582,462	310	79.49%	65,619,458	48.02%	30.
31.	500,001-750,000	53	31,967,423	319	85.29%	97,388,977	59.96%	37	22,113,838	347	88.97%	87,733,296	64.21%	31.
32.	750,001-1,000,000	23	19,482,100	342	91.44%	116,871,077	71.95%	20	17,267,800	367	94.10%	105,001,096	76.84%	32.
33.	Over 1,000,000	32	45,555,500	374	100.00%	162,426,577	100.00%	23	31,640,900	390	100.00%	136,641,996	100.00%	33.

Average Number of Customers:	62		Average Number of Customers:	65	
Average Consumption:	434,296	kWh per bill	Average Consumption:	350,364	kWh per bill
Median Consumption:	305,800	kWh per bill	Median Consumption:	231,720	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-34, E-34 Primary, E-34 Transmission (excludes AG-1)**
DESCR PTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						W NTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	1	-	1	0.97%	-	0.00%	-	-	-	0.00%	-	0 00%	*1.*
2.	1-100,000	-	-	1	0.97%	-	0.00%	1	72,000	1	0.90%	72,000	0 03%	*2.*
3.	100.001-250,000	-	-	1	0.97%	-	0.00%	-	-	1	0.90%	72,000	0.03%	*3.*
4.	250,001-500,000	-	-	1	0.97%	-	0.00%	-	-	1	0.90%	72,000	0.03%	*4.*
5.	500,001-600,000	-	-	1	0.97%	-	0.00%	3	1,645,600	4	3.60%	1,717,600	0.62%	*5.*
6.	600,001-700,000	5	3,187,200	6	5.83%	3,187,200	1.02%	-	-	4	3.60%	1,717,600	0.62%	*6.*
7.	700,001-800,000	-	-	6	5.83%	3,187,200	1.02%	3	2,212,800	7	6.31%	3,930,400	1.42%	*7.*
8.	800,001-900,000	1	829,100	7	6.80%	4,016,300	1.28%	1	856,800	8	7.21%	4,787,200	1.73%	*8.*
9.	900,001-1,000,000	2	1,893,600	9	8.74%	5,909,900	1.89%	2	1,944,000	10	9.01%	6,731,200	2.43%	*9.*
10.	1,000,001-1,250,000	4	4,392,000	13	12.62%	10,301,900	3.29%	8	9,458,400	18	16.22%	16,189,600	5 84%	*10.*
11.	1,250,001-1,500,000	7	9,778,600	20	19.42%	20,080,500	6.42%	13	17,883,600	31	27.93%	34,073,200	12.30%	*11.*
12.	1,500,001-1,750,000	6	10,138,400	26	25.24%	30,218,900	9.66%	6	9,371,400	37	33.33%	43,444,600	15.68%	*12.*
13.	1,750,001-2,000,000	4	7,500,900	30	29.13%	37,719,800	12 06%	14	26,593,592	51	45.95%	70,038,192	25.28%	*13.*
14.	2,000,001-2,250,000	8	17,363,200	38	36.89%	55,083,000	17 61%	7	14,988,500	58	52.25%	85,026,692	30.69%	*14.*
15.	2,250,001-2,500,000	3	7,023,100	41	39.81%	62,106,100	19 85%	8	19,132,925	66	59.46%	104,159,617	37.60%	*15.*
16.	2,500,001-2,750,000	5	13,073,600	46	44.66%	75,179,700	24 03%	6	15,455,479	72	64.86%	119,615,096	43.18%	*16.*
17.	2,750,001-3,000,000	18	51,299,730	64	62.14%	126,479,430	40.43%	10	28,730,119	82	73.87%	148,345,215	53 55%	*17.*
18.	3,000,001-3,250,000	4	12,328,150	68	66.02%	138,807,580	44 37%	8	24,789,461	90	81.08%	173,134,676	62.49%	*18.*
19.	3,250,001-3,500,000	6	20,067,600	74	71.84%	158,875,180	50.79%	8	26,632,068	98	88.29%	199,766,744	72.11%	*19.*
20.	3,500,001-3,750,000	1	3,729,600	75	72.82%	162,604,780	51 98%	1	3,535,600	99	89.19%	203,302,344	73 38%	*20.*
21.	3,750,001-4,000,000	3	11,419,958	78	75.73%	174,024,738	55 63%	-	-	99	89.19%	203,302,344	73 38%	*21.*
22.	4,000,001-4,500,000	7	29,016,367	85	82.52%	203,041,105	64 91%	1	4,334,352	100	90.09%	207,636,696	74 95%	*22.*
23.	4,500,001-5,000,000	6	28,290,140	91	88.35%	231,331,245	73 95%	1	4,924,800	101	90.99%	212,561,496	76.72%	*23.*
24.	5,000,001-6,000,000	2	11,556,654	93	90.29%	242,887,899	77 65%	5	29,160,000	106	95.50%	241,721,496	87 25%	*24.*
25.	6,000,001-7,000,000	5	33,510,642	98	95.15%	276,398,541	88 36%	4	25,444,800	110	99.10%	267,166,296	96.43%	*25.*
26.	7,000,001-8,000,000	5	36,409,092	103	100.00%	312,807,633	100.00%	-	-	110	99.10%	267,166,296	96.43%	*26.*
27.	8,000,001-9,000,000	-	-	103	100.00%	312,807,633	100.00%	-	-	110	99.10%	267,166,296	96.43%	*27.*
28.	9,000,001-10,000,000	-	-	103	100.00%	312,807,633	100.00%	1	9,878,400	111	100.00%	277,044,696	100.00%	*28.*
29.	10,000,001-12,500,000	-	-	103	100.00%	312,807,633	100.00%	-	-	111	100.00%	277,044,696	100.00%	*29.*
30.	12,500,001-15,000,000	-	-	103	100.00%	312,807,633	100.00%	-	-	111	100.00%	277,044,696	100.00%	*30.*
31.	15,000,001-20,000,000	-	-	103	100.00%	312,807,633	100.00%	-	-	111	100.00%	277,044,696	100.00%	*31.*
32.	20,000,001-30,000,000	-	-	103	100.00%	312,807,633	100.00%	-	-	111	100.00%	277,044,696	100.00%	*32.*
33.	Over 30,000,000	-	-	103	100.00%	312,807,633	100.00%	-	-	111	100.00%	277,044,696	100.00%	*33.*
		Average Number of Customers:		17				Average Number of Customers:		19				
		Average Consumption:		3,036,967	kWh per bill			Average Consumption:		2,495,898	kWh per bill			
		Median Consumption:		2,813,500	kWh per bill			Median Consumption:		2,150,000	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-35, E-35 Primary, E-35 Transmission (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0 00%	1.
2.	1-100,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0 00%	2.
3.	100 001-250,000	2	331,200	2	1.00%	331,200	0.05%	1	224,000	1	0.45%	224,000	0 04%	3.
4.	250,001-500,000	4	1,550,000	6	2.99%	1,881,200	0.29%	4	1,537,300	5	2.27%	1,761,300	0 29%	4.
5.	500,001-600,000	4	2,323,600	10	4.98%	4,204,800	0.64%	6	3,419,300	11	5.00%	5,180,600	0 86%	5.
6.	600,001-700,000	10	6,401,600	20	9.95%	10,606,400	1.61%	7	4,360,600	18	8.18%	9,541,200	1 59%	6.
7.	700,001-800,000	3	2,296,700	23	11.44%	12,903,100	1.96%	9	6,654,000	27	12.27%	16,195,200	2 69%	7.
8.	800,001-900,000	-	-	23	11.44%	12,903,100	1.96%	2	1,726,000	29	13.18%	17,921,200	2 98%	8.
9.	900,001-1,000,000	3	2,967,000	26	12.94%	15,870,100	2.41%	2	1,871,000	31	14.09%	19,792,200	3 29%	9.
10.	1,000,001-1,250,000	5	5,740,400	31	15.42%	21,610,500	3.29%	9	10,277,000	40	18.18%	30,069,200	5 00%	10.
11.	1,250,001-1,500,000	5	7,077,507	36	17 91%	28,688,007	4.36%	14	19,000,200	54	24.55%	49,069,400	8.16%	11.
12.	1,500,001-1,750,000	5	8,134,818	41	20.40%	36,822,825	5.60%	12	19,768,800	66	30.00%	68,838,200	11.45%	12.
13.	1,750,001-2,000,000	9	16,945,862	50	24 88%	53,768,687	8.18%	20	38,290,100	86	39.09%	107,128,300	17.82%	13.
14.	2,000,001-2,250,000	22	46,971,065	72	35 82%	100,739,752	15.32%	29	61,417,100	115	52.27%	168,545,400	28.04%	14.
15.	2,250,001-2,500,000	15	35,765,745	87	43 28%	136,505,497	20.76%	19	45,278,541	134	60.91%	213,823,941	35.57%	15.
16.	2,500,001-2,750,000	18	47,075,567	105	52 24%	183,581,064	27.92%	16	41,955,858	150	68.18%	255,779,799	42.56%	16.
17.	2,750,001-3,000,000	15	42,690,242	120	59.70%	226,271,306	34.42%	11	31,432,696	161	73.18%	287,212,495	47.79%	17.
18.	3,000,001-3,250,000	15	47,046,259	135	67.16%	273,317,565	41.57%	12	37,414,600	173	78.64%	324,627,095	54.01%	18.
19.	3,250,001-3,500,000	9	30,285,922	144	71.64%	303,603,487	46.18%	11	37,003,468	184	83.64%	361,630,563	60.17%	19.
20.	3,500,001-3,750,000	4	14,403,610	148	73 63%	318,007,097	48.37%	1	3,649,300	185	84.09%	365,279,863	60.77%	20.
21.	3,750,001-4,000,000	6	22,906,562	154	76 62%	340,913,659	51.86%	4	15,342,831	189	85.91%	380,622,694	63.33%	21.
22.	4,000,001-4,500,000	6	25,662,024	160	79 60%	366,575,683	55.76%	2	8,655,000	191	86 82%	389,277,694	64.77%	22.
23.	4,500,001-5,000,000	11	52,495,871	171	85 07%	419,071,554	63.74%	3	13,910,400	194	88.18%	403,188,094	67.08%	23.
24.	5,000,001-6,000,000	5	27,356,400	176	87 56%	446,427,954	67.91%	7	39,072,086	201	91 36%	442,260,180	73.58%	24.
25.	6,000,001-7,000,000	7	45,221,000	183	91 04%	491,648,954	74.78%	7	44,634,268	208	94 55%	486,894,448	81.01%	25.
26.	7,000,001-8,000,000	8	59,556,735	191	95 02%	551,205,689	83.84%	5	37,695,065	213	96 82%	524,589,513	87.28%	26.
27.	8,000,001-9,000,000	-	-	191	95.02%	551,205,689	83.84%	1	8,338,000	214	97.27%	532,927,513	88.67%	27.
28.	9,000,001-10,000,000	2	19,018,143	193	96 02%	570,223,832	86.74%	1	9,074,000	215	97.73%	542,001,513	90.18%	28.
29.	10,000,001-12,500,000	8	87,202,450	201	100.00%	657,426,282	100 00%	4	46,135,000	219	99.55%	588,136,513	97.85%	29.
30.	12,500,001-15,000,000	-	-	201	100 00%	657,426,282	100 00%	1	12,915,000	220	100.00%	601,051,513	100.00%	30.
31.	15,000,001-20,000,000	-	-	201	100 00%	657,426,282	100 00%	-	-	220	100.00%	601,051,513	100.00%	31.
32.	20,000,001-30,000,000	-	-	201	100 00%	657,426,282	100 00%	-	-	220	100.00%	601,051,513	100.00%	32.
33.	Over 30,000,000	-	-	201	100 00%	657,426,282	100 00%	-	-	220	100.00%	601,051,513	100.00%	33.

Average Number of Customers:	34		Average Number of Customers:	37	
Average Consumption:	3,270,778	kWh per bill	Average Consumption:	2,732,052	kWh per bill
Median Consumption:	2,620,800	kWh per bill	Median Consumption:	2,202,000	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
B LL NG ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-67**
DESCRIPTION: Classified Electric Rate Applicable to Specific Territory Served by Company

ANNUAL

Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	CUMULATIVE BILLS Number	CUMULATIVE BILLS % of Total	CUMULATIVE CONSUMPTION Amount (kWh)	CUMULATIVE CONSUMPTION % of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1.	0	103	-	103	5.54%	-	0.00%	1.
2.	1-100	71	4,491	174	9.36%	4,491	0.06%	2.
3.	101-200	570	93,036	744	40.04%	97,527	1.41%	3.
4.	201-300	275	65,017	1,019	54.84%	162,544	2.35%	4.
5.	301-400	124	44,242	1,143	61.52%	206,786	2.98%	5.
6.	401-500	157	70,993	1,300	69.97%	277,779	4.01%	6.
7.	501-750	182	109,940	1,482	79.76%	387,719	5.59%	7.
8.	751-1,000	49	40,276	1,531	82.40%	427,995	6.18%	8.
9.	1,001-1,500	53	66,214	1,584	85.25%	494,209	7.13%	9.
10.	1,501-2,000	27	46,387	1,611	86.71%	540,596	7.80%	10.
11.	2,001-3,000	52	130,690	1,663	89.50%	671,286	9.69%	11.
12.	3,001-4,000	36	124,379	1,699	91.44%	795,665	11.48%	12.
13.	4,001-5,000	27	119,756	1,726	92.90%	915,421	13.21%	13.
14.	5,001-7,500	32	185,798	1,758	94.62%	1,101,219	15.89%	14.
15.	7,501-10,000	24	215,236	1,782	95.91%	1,316,455	18.99%	15.
16.	10,001-15,000	29	359,979	1,811	97.47%	1,676,434	24.19%	16.
17.	15,001-20,000	8	131,000	1,819	97.90%	1,807,434	26.08%	17.
18.	20,001-25,000	5	111,600	1,824	98.17%	1,919,034	27.69%	18.
19.	25,001-30,000	4	105,840	1,828	98.39%	2,024,874	29.22%	19.
20.	30,001-35,000	1	30,360	1,829	98.44%	2,055,234	29.65%	20.
21.	35,001-40,000	1	39,960	1,830	98.49%	2,095,194	30.23%	21.
22.	40,001-50,000	-	-	1,830	98.49%	2,095,194	30.23%	22.
23.	50,001-75,000	15	957,160	1,845	99.30%	3,052,354	44.04%	23.
24.	75,001-100,000	-	-	1,845	99.30%	3,052,354	44.04%	24.
25.	100,001-125,000	-	-	1,845	99.30%	3,052,354	44.04%	25.
26.	125,001-150,000	-	-	1,845	99.30%	3,052,354	44.04%	26.
27.	150,001-200,000	-	-	1,845	99.30%	3,052,354	44.04%	27.
28.	200,001-300,000	8	2,134,200	1,853	99.73%	5,186,554	74.83%	28.
29.	300,001-400,000	4	1,337,400	1,857	99.95%	6,523,954	94.13%	29.
30.	400,001-500,000	1	406,800	1,858	100.00%	6,930,754	100.00%	30.
31.	500,001-750,000	-	-	1,858	100.00%	6,930,754	100.00%	31.
32.	750,001-1,000,000	-	-	1,858	100.00%	6,930,754	100.00%	32.
33.	Over 1,000,000	-	-	1,858	100.00%	6,930,754	100.00%	33.
			-					

Average Number of Customers:	155	
Average Consumption:	3,730	kWh per bill
Median Consumption:	244	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **GS-SCHOOLS TOU LARGE**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						W NTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	28	-	28	11.86%	-	0.00%	26	-	26	9.85%	-	0 00%	*1.*
2.	1-100,000	-	-	28	11.86%	-	0.00%	-	-	26	9.85%	-	0 00%	*2.*
3.	100 001-250,000	-	-	28	11.86%	-	0.00%	-	-	26	9.85%	-	0 00%	*3.*
4.	250,001-500,000	-	-	28	11.86%	-	0.00%	-	-	26	9.85%	-	0 00%	*4.*
5.	500,001-600,000	-	-	28	11.86%	-	0.00%	-	-	26	9.85%	-	0 00%	*5.*
6.	600,001-700,000	-	-	28	11.86%	-	0.00%	-	-	26	9.85%	-	0 00%	*6.*
7.	700,001-800,000	-	-	28	11.86%	-	0.00%	1	644	27	10.23%	644	0 00%	*7.*
8.	800,001-900,000	-	-	28	11.86%	-	0.00%	-	-	27	10.23%	644	0 00%	*8.*
9.	900,001-1,000,000	-	-	28	11.86%	-	0.00%	-	-	27	10.23%	644	0 00%	*9.*
10.	1,000,001-1,250,000	-	-	28	11.86%	-	0.00%	1	1,886	28	10.61%	2,530	0 01%	*10.*
11.	1,250,001-1,500,000	-	-	28	11.86%	-	0.00%	-	-	28	10.61%	2,530	0 01%	*11.*
12.	1,500,001-1,750,000	-	-	28	11.86%	-	0.00%	1	3,768	29	10.98%	6,298	0 03%	*12.*
13.	1,750,001-2,000,000	-	-	28	11.86%	-	0.00%	-	-	29	10.98%	6,298	0 03%	*13.*
14.	2,000,001-2,250,000	1	7,024	29	12.29%	7,024	0.02%	5	32,735	34	12.88%	39,033	0 21%	*14.*
15.	2,250,001-2,500,000	-	-	29	12.29%	7,024	0.02%	2	16,960	36	13.64%	55,993	0 31%	*15.*
16.	2,500,001-2,750,000	2	25,775	31	13.14%	32,799	0.11%	-	-	36	13.64%	55,993	0 31%	*16.*
17.	2,750,001-3,000,000	1	18,391	32	13 56%	51,190	0.17%	10	171,644	46	17.42%	227,637	1 25%	*17.*
18.	3,000,001-3,250,000	-	-	32	13.56%	51,190	0.17%	3	62,837	49	18.56%	290,474	1 59%	*18.*
19.	3,250,001-3,500,000	-	-	32	13 56%	51,190	0.17%	8	223,830	57	21.59%	514,304	2 81%	*19.*
20.	3,500,001-3,750,000	2	65,002	34	14.41%	116,192	0.38%	6	195,012	63	23.86%	709,316	3 88%	*20.*
21.	3,750,001-4,000,000	2	74,650	36	15 25%	190,842	0.63%	10	372,842	73	27.65%	1,082,158	5 92%	*21.*
22.	4,000,001-4,500,000	6	274,884	42	17 80%	465,726	1.53%	16	705,055	89	33.71%	1,787,213	9.78%	*22.*
23.	4,500,001-5,000,000	9	589,974	51	21 61%	1,055,700	3.46%	59	3,749,123	148	56.06%	5,536,336	30.30%	*23.*
24.	5,000,001-6,000,000	26	2,339,281	77	32 63%	3,394,981	11.13%	60	5,154,979	208	78.79%	10,691,315	58.51%	*24.*
25.	6,000,001-7,000,000	34	3,879,500	111	47 03%	7,274,481	23.86%	20	2,183,344	228	86 36%	12,874,659	70.46%	*25.*
26.	7,000,001-8,000,000	33	4,586,024	144	61 02%	11,860,505	38.89%	22	3,007,504	250	94.70%	15,882,163	86.92%	*26.*
27.	8,000,001-9,000,000	57	9,819,266	201	85.17%	21,679,771	71.09%	13	2,155,888	263	99.62%	18,038,051	98.72%	*27.*
28.	9,000,001-10,000,000	29	6,596,568	230	97.46%	28,276,339	92.73%	1	233,127	264	100.00%	18,271,178	100.00%	*28.*
29.	10,000,001-12,500,000	4	1,298,854	234	99.15%	29,575,193	96.99%	-	-	264	100.00%	18,271,178	100.00%	*29.*
30.	12,500,001-15,000,000	2	919,094	236	100.00%	30,494,287	100 00%	-	-	264	100.00%	18,271,178	100.00%	*30.*
31.	15,000,001-20,000,000	-	-	236	100.00%	30,494,287	100 00%	-	-	264	100.00%	18,271,178	100.00%	*31.*
32.	20,000,001-30,000,000	-	-	236	100.00%	30,494,287	100 00%	-	-	264	100.00%	18,271,178	100.00%	*32.*
33.	Over 30,000,000	-	-	236	100.00%	30,494,287	100 00%	-	-	264	100.00%	18,271,178	100.00%	*33.*
		Average Number of Customers:		39				Average Number of Customers:		44				
		Average Consumption:		129,213	kWh per bill			Average Consumption:		69,209	kWh per bill			
		Median Consumption:		132,534	kWh per bill			Median Consumption:		69,786	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **GS-SCHOOLS TOU MEDIUM**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	195	-	195	15.49%	-	0.00%	165	-	165	11.61%	-	0 00%	1.
2.	1-100,000	1	16	196	15.57%	16	0.00%	2	92	167	11.75%	92	0 00%	2.
3.	100 001-250,000	-	-	196	15.57%	16	0.00%	2	341	169	11.89%	433	0 00%	3.
4.	250,001-500,000	-	-	196	15.57%	16	0.00%	1	208	170	11.96%	641	0 00%	4.
5.	500,001-600,000	-	-	196	15.57%	16	0.00%	2	775	172	12.10%	1,416	0 00%	5.
6.	600,001-700,000	-	-	196	15.57%	16	0.00%	2	867	174	12.24%	2,283	0 01%	6.
7.	700,001-800,000	4	2,281	200	15.89%	2,297	0.00%	5	3,223	179	12.60%	5,506	0 01%	7.
8.	800,001-900,000	-	-	200	15 89%	2,297	0.00%	10	9,261	189	13.30%	14,767	0 03%	8.
9.	900,001-1,000,000	5	6,368	205	16.28%	8,665	0.01%	9	11,007	198	13.93%	25,774	0 06%	9.
10.	1,000,001-1,250,000	4	7,033	209	16.60%	15,698	0.03%	13	23,209	211	14.85%	48,983	0.11%	10.
11.	1,250,001-1,500,000	5	13,451	214	17.00%	29,149	0.05%	26	62,816	237	16.68%	111,799	0 25%	11.
12.	1,500,001-1,750,000	11	39,670	225	17.87%	68,819	0.12%	19	68,218	256	18.02%	180,017	0.41%	12.
13.	1,750,001-2,000,000	4	18,690	229	18.19%	87,509	0.15%	16	71,858	272	19.14%	251,875	0 57%	13.
14.	2,000,001-2,250,000	20	126,482	249	19.78%	213,991	0.37%	53	332,738	325	22.87%	584,613	1 33%	14.
15.	2,250,001-2,500,000	21	187,829	270	21.45%	401,820	0.69%	49	433,869	374	26.32%	1,018,482	2 31%	15.
16.	2,500,001-2,750,000	47	569,574	317	25.18%	971,394	1.67%	116	1,412,763	490	34.48%	2,431,245	5 52%	16.
17.	2,750,001-3,000,000	59	1,043,763	376	29.86%	2,015,157	3.47%	100	1,718,684	590	41.52%	4,149,929	9.42%	17.
18.	3,000,001-3,250,000	62	1,411,540	438	34.79%	3,426,697	5.90%	61	1,379,210	651	45.81%	5,529,139	12.55%	18.
19.	3,250,001-3,500,000	61	1,664,099	499	39.63%	5,090,796	8.77%	93	2,559,839	744	52.36%	8,088,978	18.36%	19.
20.	3,500,001-3,750,000	49	1,595,173	548	43.53%	6,685,969	11.52%	101	3,253,578	845	59.47%	11,342,556	25.75%	20.
21.	3,750,001-4,000,000	45	1,693,844	593	47.10%	8,379,813	14.43%	98	3,672,059	943	66.36%	15,014,615	34.08%	21.
22.	4,000,001-4,500,000	99	4,486,914	692	54.96%	12,866,727	22.16%	162	7,278,501	1,105	77.76%	22,293,116	50.61%	22.
23.	4,500,001-5,000,000	291	18,028,121	983	78 08%	30,894,848	53.21%	233	14,114,152	1,338	94.16%	36,407,268	82.65%	23.
24.	5,000,001-6,000,000	169	14,473,902	1,152	91 50%	45,368,750	78.15%	65	5,464,177	1,403	98.73%	41,871,445	95.05%	24.
25.	6,000,001-7,000,000	74	8,109,132	1,226	97 38%	53,477,882	92.11%	13	1,479,624	1,416	99 65%	43,351,069	98.41%	25.
26.	7,000,001-8,000,000	29	3,927,326	1,255	99 68%	57,405,208	98.88%	4	544,336	1,420	99 93%	43,895,405	99.64%	26.
27.	8,000,001-9,000,000	4	651,812	1,259	100.00%	58,057,020	100 00%	1	156,685	1,421	100.00%	44,052,090	100.00%	27.
28.	9,000,001-10,000,000	-	-	1,259	100.00%	58,057,020	100 00%	-	-	1,421	100.00%	44,052,090	100.00%	28.
29.	10,000,001-12,500,000	-	-	1,259	100 00%	58,057,020	100 00%	-	-	1,421	100.00%	44,052,090	100.00%	29.
30.	12,500,001-15,000,000	-	-	1,259	100 00%	58,057,020	100 00%	-	-	1,421	100.00%	44,052,090	100.00%	30.
31.	15,000,001-20,000,000	-	-	1,259	100 00%	58,057,020	100 00%	-	-	1,421	100.00%	44,052,090	100.00%	31.
32.	20,000,001-30,000,000	-	-	1,259	100 00%	58,057,020	100 00%	-	-	1,421	100.00%	44,052,090	100.00%	32.
33.	Over 30,000,000	-	-	1,259	100 00%	58,057,020	100 00%	-	-	1,421	100.00%	44,052,090	100.00%	33.

Average Number of Customers:	210		Average Number of Customers:	237	
Average Consumption:	46,114	kWh per bill	Average Consumption:	31,001	kWh per bill
Median Consumption:	43,835	kWh per bill	Median Consumption:	28,267	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-221 and E-221-8T**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				B LLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF B LLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	337	-	337	4.11%	-	0 00%	523	-	523	6.40%	-	0 00%	*1.*
2.	1-100	391	17,496	728	8 87%	17,496	0 01%	481	21,197	1,004	12.28%	21,197	0 02%	*2.*
3.	101-200	196	28,004	924	11 26%	45,500	0 02%	244	35,565	1,248	15.27%	56,762	0 04%	*3.*
4.	201-300	124	30,471	1,048	12.77%	75,971	0 04%	186	46,266	1,434	17.54%	103,028	0 07%	*4.*
5.	301-400	134	46,990	1,182	14.40%	122,961	0 06%	190	66,783	1,624	19.87%	169,811	0.12%	*5.*
6.	401-500	116	53,470	1,298	15 82%	176,431	0 09%	139	63,604	1,763	21.57%	233,415	0.17%	*6.*
7.	501-750	258	164,464	1,556	18 96%	340,895	0.17%	338	211,992	2,101	25.70%	445,407	0 32%	*7.*
8.	751-1,000	251	217,828	1,807	22 02%	558,723	0 28%	329	284,706	2,430	29.72%	730,113	0 53%	*8.*
9.	1,001-1,500	401	500,179	2,208	26 91%	1,058,902	0.54%	439	544,837	2,869	35.09%	1,274,950	0 92%	*9.*
10.	1,501-2,000	308	537,881	2,516	30 66%	1,596,783	0.81%	330	571,152	3,199	39.13%	1,846,102	1 34%	*10.*
11.	2,001-3,000	459	1,135,853	2,975	36 25%	2,732,636	1.39%	505	1,259,785	3,704	45.31%	3,105,887	2.25%	*11.*
12.	3,001-4,000	360	1,259,146	3,335	40 64%	3,991,782	2.03%	405	1,419,117	4,109	50.26%	4,525,004	3.28%	*12.*
13.	4,001-5,000	287	1,294,111	3,622	44.14%	5,285,893	2.69%	320	1,437,694	4,429	54.18%	5,962,698	4.32%	*13.*
14.	5,001-7,500	580	3,570,785	4,202	51.21%	8,856,678	4.51%	586	3,633,470	5,015	61.35%	9,596,168	6.95%	*14.*
15.	7,501-10,000	430	3,759,426	4,632	56.45%	12,616,104	6.42%	428	3,731,097	5,443	66.58%	13,327,265	9.66%	*15.*
16.	10,001-15,000	586	7,267,040	5,218	63.59%	19,883,144	10.11%	591	7,253,125	6,034	73.81%	20,580,390	14.91%	*16.*
17.	15,001-20,000	491	8,588,502	5,709	69.57%	28,471,646	14.48%	422	7,316,659	6,456	78.97%	27,897,049	20 21%	*17.*
18.	20,001-25,000	374	8,369,962	6,083	74.13%	36,841,608	18.74%	278	6,214,758	6,734	82.37%	34,111,807	24.72%	*18.*
19.	25,001-30,000	285	7,859,238	6,368	77 60%	44,700,846	22.74%	205	5,648,588	6,939	84.88%	39,760,395	28.81%	*19.*
20.	30,001-35,000	257	8,316,820	6,625	80.73%	53,017,666	26.97%	187	6,069,409	7,126	87.17%	45,829,804	33.21%	*20.*
21.	35,001-40,000	214	8,007,112	6,839	83 34%	61,024,778	31.04%	150	5,581,366	7,276	89.00%	51,411,170	37.25%	*21.*
22.	40,001-50,000	295	13,216,443	7,134	86 94%	74,241,221	37.77%	211	9,467,117	7,487	91.58%	60,878,287	44.11%	*22.*
23.	50,001-75,000	466	28,369,159	7,600	92 62%	102,610,380	52.20%	290	17,654,086	7,777	95.13%	78,532,373	56.90%	*23.*
24.	75,001-100,000	218	18,567,340	7,818	95 27%	121,177,720	61.64%	133	11,414,700	7,910	96.76%	89,947,073	65.18%	*24.*
25.	100,001-125,000	137	15,059,100	7,955	96.94%	136,236,820	69.30%	88	9,861,800	7,998	97.83%	99,808,873	72.32%	*25.*
26.	125,001-150,000	60	8,183,320	8,015	97.67%	144,420,140	73.47%	50	6,911,700	8,048	98.45%	106,720,573	77.33%	*26.*
27.	150,001-200,000	85	14,428,060	8,100	98.71%	158,848,200	80.81%	61	10,478,560	8,109	99.19%	117,199,133	84.92%	*27.*
28.	200,001-300,000	61	14,402,740	8,161	99.45%	173,250,940	88.13%	36	8,439,280	8,145	99.63%	125,638,413	91.04%	*28.*
29.	300,001-400,000	17	5,778,400	8,178	99 66%	179,029,340	91.07%	17	5,731,880	8,162	99.84%	131,370,293	95.19%	*29.*
30.	400,001-500,000	7	3,034,440	8,185	99.74%	182,063,780	92 62%	6	2,624,760	8,168	99.91%	133,995,053	97.09%	*30.*
31.	500,001-750,000	16	10,269,980	8,201	99 94%	192,333,760	97.84%	7	4,012,800	8,175	100.00%	138,007,853	100.00%	*31.*
32.	750,001-1,000,000	4	3,210,240	8,205	99 99%	195,544,000	99.47%	-	-	8,175	100.00%	138,007,853	100.00%	*32.*
33.	Over 1,000,000	1	1,032,060	8,206	100 00%	196,576,060	100.00%	-	-	8,175	100.00%	138,007,853	100.00%	*33.*

Average Number of Customers:	1,368		Average Number of Customers:	1,363	
Average Consumption:	23,955	kWh per bill	Average Consumption:	16,882	kWh per bill
Median Consumption:	7,003	kWh per bill	Median Consumption:	3,938	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-36 XL**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

ANNUAL

Line No.	BLOCK (kWh) (A)	NUMBER OF B LLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	CUMULATIVE BILLS Number (D)	CUMULATIVE BILLS % of Total (E)	CUMULATIVE CONSUMPTION Amount (kWh) (F)	CUMULATIVE CONSUMPTION % of Total (G)	Line No.
1.								1.
2.								2.
3.		B LLING DETERMINANTS FOR E-36 CUSTOMERS ARE NOT UTILIZED						3.
4.		IN REVENUE REQUIREMENT CALCULATIONS						4.
5.								5.
6.								6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-47**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	
1.								*1.*
2.								*2.*
3.								*3.*
4.		LIGHT NG CUSTOMERS ARE NOT BILLED BY KW OR KWH						*4.*
5.								*5.*
6.								*6.*
7.								*7.*
8.								*8.*
9.								*9.*
10.								*10.*
11.								*11.*
12.								*12.*
13.								*13.*
14.								*14.*
15.								*15.*
16.								*16.*
17.								*17.*
18.								*18.*
19.								*19.*
20.								*20.*
21.								*21.*
22.								*22.*
23.								*23.*
24.								*24.*
25.								*25.*
26.								*26.*
27.								*27.*
28.								*28.*
29.								*29.*
30.								*30.*
31.								*31.*
32.								*32.*
33.								*33.*

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-58**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	
1.								*1.*
2.								*2.*
3.								*3.*
4.								*4.*
5.								*5.*
6.		LIGHT NG CUSTOMERS ARE NOT BILLED BY KW OR KWH						*6.*
7.								*7.*
8.								*8.*
9.								*9.*
10.								*10.*
11.								*11.*
12.								*12.*
13.								*13.*
14.								*14.*
15.								*15.*
16.								*16.*
17.								*17.*
18.								*18.*
19.								*19.*
20.								*20.*
21.								*21.*
22.								*22.*
23.								*23.*
24.								*24.*
25.								*25.*
26.								*26.*
27.								*27.*
28.								*28.*
29.								*29.*
30.								*30.*
31.								*31.*
32.								*32.*
33.								*33.*

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-59**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	
1.								*1.*
2.								*2.*
3.								*3.*
4.								*4.*
5.								*5.*
6.		LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH						*6.*
7.								*7.*
8.								*8.*
9.								*9.*
10.								*10.*
11.								*11.*
12.								*12.*
13.								*13.*
14.								*14.*
15.								*15.*
16.								*16.*
17.								*17.*
18.								*18.*
19.								*19.*
20.								*20.*
21.								*21.*
22.								*22.*
23.								*23.*
24.								*24.*
25.								*25.*
26.								*26.*
27.								*27.*
28.								*28.*
29.								*29.*
30.								*30.*
31.								*31.*
32.								*32.*
33.								*33.*

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **CONTRACT 12**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	
1.								*1.*
2.								*2.*
3.								*3.*
4.								*4.*
5.								*5.*
6.		LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH						*6.*
7.								*7.*
8.								*8.*
9.								*9.*
10.								*10.*
11.								*11.*
12.								*12.*
13.								*13.*
14.								*14.*
15.								*15.*
16.								*16.*
17.								*17.*
18.								*18.*
19.								*19.*
20.								*20.*
21.								*21.*
22.								*22.*
23.								*23.*
24.								*24.*
25.								*25.*
26.								*26.*
27.								*27.*
28.								*28.*
29.								*29.*
30.								*30.*
31.								*31.*
32.								*32.*
33.								*33.*

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-20**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	15	-	15	0 67%	-	0.00%	18	-	18	0.81%	-	0.00%	*1.*
2.	1-10	238	1,519	253	11.32%	1,519	1.41%	555	3,464	573	25.74%	3,464	5.16%	*2.*
3.	11-20	343	5,378	596	26.67%	6,897	6.40%	612	9,508	1,185	53.23%	12,972	19.31%	*3.*
4.	21-30	388	9,832	984	44.03%	16,729	15.53%	352	8,818	1,537	69.05%	21,790	32.44%	*4.*
5.	31-40	240	8,477	1,224	54.77%	25,206	23.40%	235	8,364	1,772	79.60%	30,154	44.89%	*5.*
6.	41-50	213	9,736	1,437	64.30%	34,942	32.44%	128	5,799	1,900	85.35%	35,953	53.52%	*6.*
7.	51-60	185	10,246	1,622	72.57%	45,188	41.95%	83	4,593	1,983	89.08%	40,546	60.35%	*7.*
8.	61-70	153	10,065	1,775	79.42%	55,253	51.29%	59	3,866	2,042	91.73%	44,412	66.11%	*8.*
9.	71-80	95	7,115	1,870	83.67%	62,368	57.89%	36	2,707	2,078	93.35%	47,119	70.14%	*9.*
10.	81-90	101	8,596	1,971	88.19%	70,964	65.87%	35	2,982	2,113	94.92%	50,101	74.58%	*10.*
11.	91-100	56	5,322	2,027	90.69%	76,286	70.81%	31	2,944	2,144	96.32%	53,045	78.96%	*11.*
12.	101-200	178	22,793	2,205	98.66%	99,079	91.97%	63	8,498	2,207	99.15%	61,543	91.61%	*12.*
13.	201-300	18	4,307	2,223	99.46%	103,386	95.97%	14	3,389	2,221	99.78%	64,932	96.65%	*13.*
14.	301-400	9	3,030	2,232	99.87%	106,416	98.78%	1	350	2,222	99.82%	65,282	97.17%	*14.*
15.	401-500	3	1,312	2,235	100.00%	107,728	100.00%	2	840	2,224	99.91%	66,122	98.43%	*15.*
16.	501-600	-	-	2,235	100.00%	107,728	100.00%	2	1,058	2,226	100.00%	67,180	100.00%	*16.*
17.	601-700	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*17.*
18.	701-800	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*18.*
19.	801-900	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*19.*
20.	901-1000	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*20.*
21.	1001-1100	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*21.*
22.	1101-1200	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*22.*
23.	1201-1300	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*23.*
24.	1301-1400	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*24.*
25.	1401-1500	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*25.*
26.	1501-1600	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*26.*
27.	1601-1700	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*27.*
28.	1701-1800	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*28.*
29.	1801-1900	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*29.*
30.	1901-2000	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*30.*
31.	2001-2100	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*31.*
32.	2101-2200	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*32.*
33.	2201-2300	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*33.*
34.	2301-2400	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*34.*
35.	2401-2500	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*35.*
36.	2501-2600	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*36.*
37.	2601-2700	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*37.*
38.	2701-2800	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*38.*
39.	2801-2900	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*39.*
40.	2901-3000	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*40.*
41.	Over 3000	-	-	2,235	100.00%	107,728	100.00%	-	-	2,226	100.00%	67,180	100.00%	*41.*
		Average Number of Customers:		373				Average Number of Customers:		371				
		Average Load:		48	kW per bill			Average Load:		30	kW per bill			
		Median Load:		36	kW per bill			Median Load:		19	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 XSD**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						W NTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				B LLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	1,301	-	1,301	14.92%	-	0.00%	1,370	-	1,370	15.89%	-	0.00%	*1.*
2.	1-10	6,097	24,839	7,398	84.86%	24,839	58.07%	5,932	24,586	7,302	84.68%	24,586	55 68%	*2.*
3.	11-20	1,267	16,464	8,665	99.39%	41,303	96.56%	1,159	15,376	8,461	98.12%	39,962	90 51%	*3.*
4.	21-30	43	1,033	8,708	99.89%	42,336	98.98%	142	3,429	8,603	99.77%	43,391	98 27%	*4.*
5.	31-40	5	167	8,713	99.94%	42,503	99.37%	16	551	8,619	99.95%	43,942	99 52%	*5.*
6.	41-50	-	-	8,713	99.94%	42,503	99.37%	2	94	8,621	99.98%	44,036	99.74%	*6.*
7.	51-60	5	271	8,718	100.00%	42,774	100.00%	2	117	8,623	100.00%	44,153	100.00%	*7.*
8.	61-70	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100 00%	*8.*
9.	71-80	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100 00%	*9.*
10.	81-90	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*10.*
11.	91-100	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*11.*
12.	101-200	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*12.*
13.	201-300	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*13.*
14.	301-400	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*14.*
15.	401-500	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*15.*
16.	501-600	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*16.*
17.	601-700	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100 00%	*17.*
18.	701-800	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100 00%	*18.*
19.	801-900	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*19.*
20.	901-1000	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*20.*
21.	1001-1100	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*21.*
22.	1101-1200	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*22.*
23.	1201-1300	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*23.*
24.	1301-1400	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*24.*
25.	1401-1500	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*25.*
26.	1501-1600	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*26.*
27.	1601-1700	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100 00%	*27.*
28.	1701-1800	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*28.*
29.	1801-1900	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*29.*
30.	1901-2000	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*30.*
31.	2001-2100	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*31.*
32.	2101-2200	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*32.*
33.	2201-2300	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*33.*
34.	2301-2400	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*34.*
35.	2401-2500	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*35.*
36.	2501-2600	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100 00%	*36.*
37.	2601-2700	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*37.*
38.	2701-2800	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*38.*
39.	2801-2900	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*39.*
40.	2901-3000	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*40.*
41.	Over 3000	-	-	8,718	100.00%	42,774	100.00%	-	-	8,623	100.00%	44,153	100.00%	*41.*
		Average Number of Customers:		1,453				Average Number of Customers:		1,437				
		Average Load:		5	kW per bill			Average Load:		5	kW per bill			
		Median Load:		4	kW per bill			Median Load:		4	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	753	-	753	0.66%	-	0.00%	923	-	923	0.80%	-	0.00%	1.
2.	1-10	1,865	9,452	2,618	2.30%	9,452	0.20%	6,007	41,067	6,930	6.00%	41,067	1.11%	2.
3.	11-20	9,933	175,011	12,551	11.00%	184,463	3.89%	32,855	535,139	39,785	34.44%	576,206	15 56%	3.
4.	21-30	36,399	923,202	48,950	42.92%	1,107,665	23.37%	31,818	796,257	71,603	61.99%	1,372,463	37 05%	4.
5.	31-40	21,257	746,812	70,207	61.55%	1,854,477	39.12%	16,860	591,824	88,463	76.59%	1,964,287	53.03%	5.
6.	41-50	13,941	630,667	84,148	73.77%	2,485,144	52.43%	10,511	474,782	98,974	85.69%	2,439,069	65.84%	6.
7.	51-60	9,126	505,495	93,274	81.78%	2,990,639	63.09%	6,272	346,894	105,246	91.12%	2,785,963	75.21%	7.
8.	61-70	6,860	448,084	100,134	87.79%	3,438,723	72.54%	4,016	261,703	109,262	94.59%	3,047,666	82 27%	8.
9.	71-80	5,075	382,331	105,209	92.24%	3,821,054	80.61%	2,529	190,075	111,791	96.78%	3,237,741	87.41%	9.
10.	81-90	3,616	308,910	108,825	95.41%	4,129,964	87.13%	1,360	115,968	113,151	97 96%	3,353,709	90 54%	10.
11.	91-100	2,420	229,961	111,245	97.53%	4,359,925	91.98%	738	70,143	113,889	98 60%	3,423,852	92.43%	11.
12.	101-200	2,631	313,139	113,876	99.84%	4,673,064	98.59%	1,384	174,349	115,273	99 80%	3,598,201	97.14%	12.
13.	201-300	117	27,096	113,993	99 94%	4,700,160	99.16%	118	27,664	115,391	99 90%	3,625,865	97 88%	13.
14.	301-400	36	12,533	114,029	99 97%	4,712,693	99.42%	22	7,599	115,413	99 92%	3,633,464	98 09%	14.
15.	401-500	8	3,564	114,037	99 98%	4,716,257	99.50%	27	11,910	115,440	99 94%	3,645,374	98.41%	15.
16.	501-600	3	1,698	114,040	99 98%	4,717,955	99.53%	13	7,533	115,453	99 95%	3,652,907	98 61%	16.
17.	601-700	7	4,422	114,047	99 99%	4,722,377	99.63%	9	5,784	115,462	99.96%	3,658,691	98.77%	17.
18.	701-800	2	1,552	114,049	99.99%	4,723,929	99.66%	13	9,773	115,475	99.97%	3,668,464	99 03%	18.
19.	801-900	-	-	114,049	99.99%	4,723,929	99.66%	5	4,224	115,480	99.98%	3,672,688	99.15%	19.
20.	901-1000	4	3,791	114,053	99.99%	4,727,720	99.74%	14	13,498	115,494	99.99%	3,686,186	99 51%	20.
21.	1001-1100	-	-	114,053	99.99%	4,727,720	99.74%	3	3,159	115,497	99.99%	3,689,345	99 60%	21.
22.	1101-1200	3	3,393	114,056	100.00%	4,731,113	99.81%	3	3,480	115,500	99.99%	3,692,825	99 69%	22.
23.	1201-1300	-	-	114,056	100.00%	4,731,113	99.81%	-	-	115,500	99.99%	3,692,825	99 69%	23.
24.	1301-1400	-	-	114,056	100.00%	4,731,113	99.81%	-	-	115,500	99.99%	3,692,825	99 69%	24.
25.	1401-1500	-	-	114,056	100.00%	4,731,113	99.81%	4	5,832	115,504	100.00%	3,698,657	99 85%	25.
26.	1501-1600	-	-	114,056	100.00%	4,731,113	99.81%	2	3,096	115,506	100.00%	3,701,753	99 93%	26.
27.	1601-1700	-	-	114,056	100.00%	4,731,113	99.81%	-	-	115,506	100.00%	3,701,753	99 93%	27.
28.	1701-1800	2	3,516	114,058	100.00%	4,734,629	99.88%	-	-	115,506	100.00%	3,701,753	99 93%	28.
29.	1801-1900	3	5,496	114,061	100.00%	4,740,125	100.00%	-	-	115,506	100.00%	3,701,753	99 93%	29.
30.	1901-2000	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,506	100.00%	3,701,753	99 93%	30.
31.	2001-2100	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,506	100.00%	3,701,753	99 93%	31.
32.	2101-2200	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,506	100.00%	3,701,753	99 93%	32.
33.	2201-2300	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,506	100.00%	3,701,753	99 93%	33.
34.	2301-2400	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,506	100.00%	3,701,753	99 93%	34.
35.	2401-2500	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,506	100.00%	3,701,753	99 93%	35.
36.	2501-2600	-	-	114,061	100.00%	4,740,125	100.00%	1	2,520	115,507	100.00%	3,704,273	100 00%	36.
37.	2601-2700	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,507	100.00%	3,704,273	100 00%	37.
38.	2701-2800	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,507	100.00%	3,704,273	100.00%	38.
39.	2801-2900	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,507	100.00%	3,704,273	100.00%	39.
40.	2901-3000	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,507	100.00%	3,704,273	100.00%	40.
41.	Over 3000	-	-	114,061	100.00%	4,740,125	100.00%	-	-	115,507	100.00%	3,704,273	100.00%	41.
		Average Number of Customers:		19,010				Average Number of Customers:		19,251				
		Average Load:		42	kW per bill			Average Load:		32	kW per bill			
		Median Load:		34	kW per bill			Median Load:		25	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Medium (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	114	-	114	0.44%	-	0.00%	141	-	141	0.54%	-	0.00%	*1.*
2.	1-10	78	378	192	0.75%	378	0.01%	139	592	280	1.07%	592	0.01%	*2.*
3.	11-20	66	1,022	258	1 00%	1,400	0.03%	95	1,470	375	1.43%	2,062	0.05%	*3.*
4.	21-30	58	1,511	316	1 23%	2,911	0.06%	144	3,746	519	1.97%	5,808	0.14%	*4.*
5.	31-40	79	2,792	395	1 53%	5,703	0.11%	222	7,911	741	2.82%	13,719	0.33%	*5.*
6.	41-50	79	3,602	474	1 84%	9,305	0.19%	417	19,317	1,158	4.41%	33,036	0.80%	*6.*
7.	51-60	90	5,025	564	2.19%	14,330	0.29%	761	42,835	1,919	7.30%	75,871	1.84%	*7.*
8.	61-70	110	7,266	674	2 62%	21,596	0.43%	1,247	82,296	3,166	12.05%	158,167	3.84%	*8.*
9.	71-80	253	19,289	927	3.60%	40,885	0.82%	1,718	130,285	4,884	18.58%	288,452	7.00%	*9.*
10.	81-90	539	46,452	1,466	5.69%	87,337	1.76%	1,752	150,154	6,636	25.25%	438,606	10.64%	*10.*
11.	91-100	993	95,147	2,459	9.55%	182,484	3.67%	1,832	174,772	8,468	32.22%	613,378	14.89%	*11.*
12.	101-200	13,934	2,015,789	16,393	63.65%	2,198,273	44.27%	11,620	1,648,056	20,088	76.43%	2,261,434	54.88%	*12.*
13.	201-300	5,984	1,459,997	22,377	86 89%	3,658,270	73.67%	4,330	1,049,784	24,418	92.90%	3,311,218	80.36%	*13.*
14.	301-400	2,598	889,692	24,975	96 98%	4,547,962	91.58%	1,346	457,371	25,764	98.02%	3,768,589	91.46%	*14.*
15.	401-500	585	253,289	25,560	99 25%	4,801,251	96.69%	260	114,561	26,024	99.01%	3,883,150	94.24%	*15.*
16.	501-600	109	58,948	25,669	99 67%	4,860,199	97 87%	82	44,523	26,106	99.32%	3,927,673	95.32%	*16.*
17.	601-700	31	20,201	25,700	99.79%	4,880,400	98 28%	42	27,545	26,148	99.48%	3,955,218	95.99%	*17.*
18.	701-800	15	10,946	25,715	99.85%	4,891,346	98.50%	36	26,928	26,184	99.62%	3,982,146	96.64%	*18.*
19.	801-900	10	8,668	25,725	99.89%	4,900,014	98.67%	13	10,943	26,197	99.67%	3,993,089	96.91%	*19.*
20.	901-1000	7	6,649	25,732	99 91%	4,906,663	98.81%	19	18,031	26,216	99.74%	4,011,120	97.34%	*20.*
21.	1001-1100	4	4,123	25,736	99 93%	4,910,786	98.89%	2	2,046	26,218	99.75%	4,013,166	97.39%	*21.*
22.	1101-1200	2	2,312	25,738	99 94%	4,913,098	98 94%	6	7,010	26,224	99.77%	4,020,176	97.56%	*22.*
23.	1201-1300	-	-	25,738	99 94%	4,913,098	98 94%	9	11,202	26,233	99.81%	4,031,378	97.84%	*23.*
24.	1301-1400	2	2,680	25,740	99 95%	4,915,778	98 99%	12	16,194	26,245	99.85%	4,047,572	98 23%	*24.*
25.	1401-1500	3	4,336	25,743	99 96%	4,920,114	99 08%	6	8,670	26,251	99.87%	4,056,242	98.44%	*25.*
26.	1501-1600	1	1,580	25,744	99 96%	4,921,694	99.11%	10	15,581	26,261	99.91%	4,071,823	98 82%	*26.*
27.	1601-1700	1	1,608	25,745	99.97%	4,923,302	99.14%	7	11,435	26,268	99.94%	4,083,258	99.09%	*27.*
28.	1701-1800	-	-	25,745	99.97%	4,923,302	99.14%	1	1,728	26,269	99.94%	4,084,986	99.14%	*28.*
29.	1801-1900	-	-	25,745	99 97%	4,923,302	99.14%	1	1,843	26,270	99.95%	4,086,829	99.18%	*29.*
30.	1901-2000	1	1,944	25,746	99 97%	4,925,246	99.18%	6	11,720	26,276	99.97%	4,098,549	99.47%	*30.*
31.	2001-2100	-	-	25,746	99 97%	4,925,246	99.18%	-	-	26,276	99.97%	4,098,549	99.47%	*31.*
32.	2101-2200	-	-	25,746	99 97%	4,925,246	99.18%	-	-	26,276	99.97%	4,098,549	99.47%	*32.*
33.	2201-2300	-	-	25,746	99 97%	4,925,246	99.18%	1	2,232	26,277	99.97%	4,100,781	99.52%	*33.*
34.	2301-2400	-	-	25,746	99 97%	4,925,246	99.18%	1	2,335	26,278	99.98%	4,103,116	99.58%	*34.*
35.	2401-2500	-	-	25,746	99 97%	4,925,246	99.18%	1	2,436	26,279	99.98%	4,105,552	99.64%	*35.*
36.	2501-2600	-	-	25,746	99.97%	4,925,246	99.18%	1	2,570	26,280	99.98%	4,108,122	99.70%	*36.*
37.	2601-2700	-	-	25,746	99.97%	4,925,246	99.18%	1	2,654	26,281	99.99%	4,110,776	99.76%	*37.*
38.	2701-2800	-	-	25,746	99.97%	4,925,246	99.18%	1	2,760	26,282	99.99%	4,113,536	99.83%	*38.*
39.	2801-2900	1	2,880	25,747	99 97%	4,928,126	99.24%	-	-	26,282	99.99%	4,113,536	99.83%	*39.*
40.	2901-3000	-	-	25,747	99 97%	4,928,126	99.24%	-	-	26,282	99.99%	4,113,536	99.83%	*40.*
41.	Over 3000	7	37,728	25,754	100 00%	4,965,854	100.00%	2	7,034	26,284	100.00%	4,120,570	100.00%	*41.*
		Average Number of Customers:		4,292				Average Number of Customers:		4,381				
		Average Load:		193	kW per bill			Average Load:		157	kW per bill			
		Median Load:		168	kW per bill			Median Load:		129	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Large (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	2	-	2	0.04%	-	0.00%	8	-	8	0.17%	-	0.00%	1.
2.	1-10	-	-	2	0.04%	-	0.00%	-	-	8	0.17%	-	0.00%	2.
3.	11-20	9	131	11	0.24%	131	0.00%	2	26	10	0 21%	26	0.00%	3.
4.	21-30	6	144	17	0.37%	275	0.01%	4	97	14	0 29%	123	0.00%	4.
5.	31-40	-	-	17	0.37%	275	0.01%	2	72	16	0 33%	195	0.01%	5.
6.	41-50	-	-	17	0.37%	275	0.01%	-	-	16	0 33%	195	0.01%	6.
7.	51-60	-	-	17	0.37%	275	0.01%	4	231	20	0.42%	426	0.01%	7.
8.	61-70	2	127	19	0.41%	402	0.01%	1	69	21	0.44%	495	0.01%	8.
9.	71-80	1	74	20	0.43%	476	0.01%	-	-	21	0.44%	495	0.01%	9.
10.	81-90	2	170	22	0.48%	646	0.02%	2	174	23	0.48%	669	0.02%	10.
11.	91-100	-	-	22	0.48%	646	0.02%	1	96	24	0 50%	765	0.02%	11.
12.	101-200	11	1,512	33	0.71%	2,158	0.06%	26	3,884	50	1 05%	4,649	0.13%	12.
13.	201-300	26	7,034	59	1.28%	9,192	0.25%	90	24,680	140	2 93%	29,329	0.83%	13.
14.	301-400	314	117,067	373	8.07%	126,259	3.47%	611	224,369	751	15.72%	253,698	7.21%	14.
15.	401-500	1,045	471,929	1,418	30.68%	598,188	16.42%	1,071	478,839	1,822	38.14%	732,537	20.80%	15.
16.	501-600	860	469,955	2,278	49.29%	1,068,143	29.31%	776	422,779	2,598	54 39%	1,155,316	32.81%	16.
17.	601-700	487	316,255	2,765	59.82%	1,384,398	37.99%	524	339,447	3,122	65 35%	1,494,763	42.45%	17.
18.	701-800	450	337,355	3,215	69.56%	1,721,753	47.25%	402	301,175	3,524	73.77%	1,795,938	51.00%	18.
19.	801-900	308	260,963	3,523	76.22%	1,982,716	54.41%	229	194,743	3,753	78 56%	1,990,681	56.54%	19.
20.	901-1000	213	202,576	3,736	80.83%	2,185,292	59.97%	180	170,846	3,933	82 33%	2,161,527	61.39%	20.
21.	1001-1100	143	150,734	3,879	83.92%	2,336,026	64.11%	158	166,791	4,091	85 64%	2,328,318	66.12%	21.
22.	1101-1200	105	120,446	3,984	86.20%	2,456,472	67.42%	124	142,411	4,215	88 24%	2,470,729	70.17%	22.
23.	1201-1300	113	141,679	4,097	88.64%	2,598,151	71.30%	69	86,413	4,284	89 68%	2,557,142	72.62%	23.
24.	1301-1400	71	96,013	4,168	90.18%	2,694,164	73.94%	72	97,741	4,356	91.19%	2,654,883	75.40%	24.
25.	1401-1500	100	146,438	4,268	92.34%	2,840,602	77.96%	115	168,634	4,471	93 59%	2,823,517	80.19%	25.
26.	1501-1600	50	77,500	4,318	93.42%	2,918,102	80.08%	53	81,420	4,524	94.70%	2,904,937	82.50%	26.
27.	1601-1700	53	87,590	4,371	94.57%	3,005,692	82.49%	26	43,011	4,550	95 25%	2,947,948	83.72%	27.
28.	1701-1800	32	55,734	4,403	95.26%	3,061,426	84.02%	20	35,265	4,570	95 67%	2,983,213	84.72%	28.
29.	1801-1900	26	48,015	4,429	95.82%	3,109,441	85.34%	21	38,905	4,591	96.11%	3,022,118	85.83%	29.
30.	1901-2000	16	31,441	4,445	96.17%	3,140,882	86.20%	34	66,662	4,625	96 82%	3,088,780	87.72%	30.
31.	2001-2100	20	41,137	4,465	96.60%	3,182,019	87.33%	31	63,830	4,656	97.47%	3,152,610	89.53%	31.
32.	2101-2200	22	46,944	4,487	97.08%	3,228,963	88.62%	29	62,422	4,685	98 07%	3,215,032	91.31%	32.
33.	2201-2300	23	51,557	4,510	97.58%	3,280,520	90.03%	7	15,571	4,692	98 22%	3,230,603	91.75%	33.
34.	2301-2400	16	37,414	4,526	97.92%	3,317,934	91.06%	11	26,138	4,703	98.45%	3,256,741	92.49%	34.
35.	2401-2500	17	41,759	4,543	98.29%	3,359,693	92.20%	15	37,032	4,718	98.76%	3,293,773	93.54%	35.
36.	2501-2600	14	35,904	4,557	98.59%	3,395,597	93.19%	8	20,234	4,726	98 93%	3,314,007	94.12%	36.
37.	2601-2700	3	7,871	4,560	98.66%	3,403,468	93.40%	1	2,688	4,727	98 95%	3,316,695	94.19%	37.
38.	2701-2800	12	33,373	4,572	98.92%	3,436,841	94.32%	13	36,107	4,740	99 23%	3,352,802	95.22%	38.
39.	2801-2900	3	8,514	4,575	98.98%	3,445,355	94.55%	-	-	4,740	99 23%	3,352,802	95.22%	39.
40.	2901-3000	11	32,736	4,586	99.22%	3,478,091	95.45%	10	29,760	4,750	99.43%	3,382,562	96.07%	40.
41.	Over 3000	36	165,690	4,622	100.00%	3,643,781	100.00%	27	138,544	4,777	100 00%	3,521,106	100.00%	41.
	Average Number of Customers:			770				Average Number of Customers:		796				
	Average Load:			788	kW per bill			Average Load:		737	kW per bill			
	Median Load:			608	kW per bill			Median Load:		568	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 Extra Small GS TOU**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						W NTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	427	-	427	10.66%	-	0.00%	460	-	460	11.40%	-	0.00%	*1.*
2.	1-10	3,098	13,801	3,525	88.04%	13,801	58.34%	3,073	13,260	3,533	87.54%	13,260	54.66%	*2.*
3.	11-20	411	5,725	3,936	98.30%	19,526	82.54%	429	6,137	3,962	98.17%	19,397	79.96%	*3.*
4.	21-30	40	904	3,976	99.30%	20,430	86.36%	37	870	3,999	99.08%	20,267	83 54%	*4.*
5.	31-40	5	187	3,981	99.43%	20,617	87.15%	18	615	4,017	99.53%	20,882	86.08%	*5.*
6.	41-50	6	266	3,987	99.58%	20,883	88.27%	7	307	4,024	99.70%	21,189	87.34%	*6.*
7.	51-60	3	160	3,990	99.65%	21,043	88.95%	-	-	4,024	99.70%	21,189	87.34%	*7.*
8.	61-70	3	188	3,993	99.73%	21,231	89.75%	-	-	4,024	99.70%	21,189	87 34%	*8.*
9.	71-80	2	156	3,995	99.78%	21,387	90.40%	2	146	4,026	99.75%	21,335	87 95%	*9.*
10.	81-90	2	178	3,997	99.83%	21,565	91.16%	1	88	4,027	99.78%	21,423	88.31%	*10.*
11.	91-100	-	-	3,997	99.83%	21,565	91.16%	-	-	4,027	99.78%	21,423	88.31%	*11.*
12.	101-200	3	563	4,000	99.90%	22,128	93.54%	4	546	4,031	99.88%	21,969	90 56%	*12.*
13.	201-300	1	210	4,001	99.93%	22,338	94.42%	2	549	4,033	99.93%	22,518	92 82%	*13.*
14.	301-400	-	-	4,001	99.93%	22,338	94.42%	-	-	4,033	99.93%	22,518	92 82%	*14.*
15.	401-500	3	1,319	4,004	100.00%	23,657	100.00%	2	865	4,035	99.98%	23,383	96 39%	*15.*
16.	501-600	-	-	4,004	100.00%	23,657	100.00%	-	-	4,035	99.98%	23,383	96 39%	*16.*
17.	601-700	-	-	4,004	100.00%	23,657	100.00%	-	-	4,035	99.98%	23,383	96 39%	*17.*
18.	701-800	-	-	4,004	100.00%	23,657	100.00%	-	-	4,035	99.98%	23,383	96.39%	*18.*
19.	801-900	-	-	4,004	100.00%	23,657	100.00%	1	876	4,036	100.00%	24,259	100 00%	*19.*
20.	901-1000	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*20.*
21.	1001-1100	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*21.*
22.	1101-1200	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*22.*
23.	1201-1300	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*23.*
24.	1301-1400	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*24.*
25.	1401-1500	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*25.*
26.	1501-1600	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*26.*
27.	1601-1700	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100 00%	*27.*
28.	1701-1800	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*28.*
29.	1801-1900	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*29.*
30.	1901-2000	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*30.*
31.	2001-2100	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*31.*
32.	2101-2200	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*32.*
33.	2201-2300	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*33.*
34.	2301-2400	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*34.*
35.	2401-2500	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*35.*
36.	2501-2600	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100 00%	*36.*
37.	2601-2700	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*37.*
38.	2701-2800	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*38.*
39.	2801-2900	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*39.*
40.	2901-3000	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*40.*
41.	Over 3000	-	-	4,004	100.00%	23,657	100.00%	-	-	4,036	100.00%	24,259	100.00%	*41.*
		Average Number of Customers:		667				Average Number of Customers:		673				
		Average Load:		6	kW per bill			Average Load:		6	kW per bill			
		Median Load:		5	kW per bill			Median Load:		4	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 TOUS**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	20	-	20	2.12%	-	0.00%	28	-	28	2.98%	-	0 00%	*1.*
2.	1-10	25	143	45	4.76%	143	0.33%	51	371	79	8.41%	371	1.10%	*2.*
3.	11-20	79	1,314	124	13.12%	1,457	3.32%	186	2,977	265	28.22%	3,348	9 95%	*3.*
4.	21-30	217	5,616	341	36.08%	7,073	16.12%	228	5,829	493	52.50%	9,177	27 27%	*4.*
5.	31-40	193	6,871	534	56.51%	13,944	31.79%	189	6,584	682	72.63%	15,761	46 84%	*5.*
6.	41-50	110	4,928	644	68.15%	18,872	43.02%	88	3,988	770	82.00%	19,749	58 69%	*6.*
7.	51-60	69	3,797	713	75.45%	22,669	51.68%	53	2,974	823	87.65%	22,723	67 53%	*7.*
8.	61-70	70	4,578	783	82.86%	27,247	62.11%	43	2,828	866	92.23%	25,551	75 93%	*8.*
9.	71-80	47	3,534	830	87.83%	30,781	70.17%	33	2,480	899	95.74%	28,031	83 30%	*9.*
10.	81-90	36	3,086	866	91.64%	33,867	77.20%	13	1,107	912	97.12%	29,138	86 59%	*10.*
11.	91-100	33	3,143	899	95.13%	37,010	84.37%	3	287	915	97.44%	29,425	87.45%	*11.*
12.	101-200	39	4,623	938	99.26%	41,633	94.91%	18	2,227	933	99.36%	31,652	94 07%	*12.*
13.	201-300	4	1,108	942	99.68%	42,741	97.43%	1	263	934	99.47%	31,915	94 85%	*13.*
14.	301-400	2	676	944	99.89%	43,417	98.97%	5	1,734	939	100.00%	33,649	100 00%	*14.*
15.	401-500	1	451	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*15.*
16.	501-600	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*16.*
17.	601-700	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*17.*
18.	701-800	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*18.*
19.	801-900	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*19.*
20.	901-1000	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*20.*
21.	1001-1100	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*21.*
22.	1101-1200	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*22.*
23.	1201-1300	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*23.*
24.	1301-1400	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*24.*
25.	1401-1500	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*25.*
26.	1501-1600	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*26.*
27.	1601-1700	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*27.*
28.	1701-1800	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*28.*
29.	1801-1900	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*29.*
30.	1901-2000	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*30.*
31.	2001-2100	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*31.*
32.	2101-2200	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*32.*
33.	2201-2300	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*33.*
34.	2301-2400	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*34.*
35.	2401-2500	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*35.*
36.	2501-2600	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*36.*
37.	2601-2700	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*37.*
38.	2701-2800	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*38.*
39.	2801-2900	-	-	945	100.00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*39.*
40.	2901-3000	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*40.*
41.	Over 3000	-	-	945	100 00%	43,868	100 00%	-	-	939	100.00%	33,649	100 00%	*41.*

Average Number of Customers:	158		Average Number of Customers:	157	
Average Load:	46	kW per bill	Average Load:	36	kW per bill
Median Load:	38	kW per bill	Median Load:	30	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 TOU MEDIUM**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	2	-	2	0.34%	-	0.00%	1	-	1	0.17%	-	0.00%	*1.*
2.	1-10	5	32	7	1.20%	32	0.02%	3	20	4	0 69%	20	0.02%	*2.*
3.	11-20	2	30	9	1.54%	62	0.04%	1	14	5	0 87%	34	0.03%	*3.*
4.	21-30	3	76	12	2.06%	138	0.10%	3	78	8	1 39%	112	0.10%	*4.*
5.	31-40	5	174	17	2.92%	312	0.22%	6	219	14	2.43%	331	0.31%	*5.*
6.	41-50	3	130	20	3.43%	442	0.31%	16	741	30	5 21%	1,072	1.00%	*6.*
7.	51-60	1	51	21	3.60%	493	0.35%	20	1,113	50	8 68%	2,185	2.04%	*7.*
8.	61-70	3	200	24	4.12%	693	0.49%	19	1,269	69	11 98%	3,454	3.23%	*8.*
9.	71-80	9	685	33	5.66%	1,378	0.98%	26	1,950	95	16.49%	5,404	5.05%	*9.*
10.	81-90	7	601	40	6.86%	1,979	1.41%	22	1,885	117	20 31%	7,289	6.82%	*10.*
11.	91-100	12	1,147	52	8.92%	3,126	2.22%	16	1,529	133	23 09%	8,818	8.25%	*11.*
12.	101-200	217	32,444	269	46.14%	35,570	25.32%	212	31,250	345	59 90%	40,068	37.47%	*12.*
13.	201-300	171	42,574	440	75.47%	78,144	55.62%	159	39,782	504	87 50%	79,850	74.67%	*13.*
14.	301-400	105	36,261	545	93.48%	114,405	81.42%	53	18,396	557	96.70%	98,246	91.87%	*14.*
15.	401-500	25	10,827	570	97.77%	125,232	89.13%	15	6,511	572	99 31%	104,757	97.96%	*15.*
16.	501-600	9	4,958	579	99.31%	130,190	92.66%	4	2,179	576	100 00%	106,936	100.00%	*16.*
17.	601-700	1	672	580	99.49%	130,862	93.13%	-	-	576	100 00%	106,936	100.00%	*17.*
18.	701-800	-	-	580	99.49%	130,862	93.13%	-	-	576	100 00%	106,936	100.00%	*18.*
19.	801-900	-	-	580	99.49%	130,862	93.13%	-	-	576	100 00%	106,936	100.00%	*19.*
20.	901-1000	1	902	581	99.66%	131,764	93.78%	-	-	576	100 00%	106,936	100.00%	*20.*
21.	1001-1100	-	-	581	99.66%	131,764	93.78%	-	-	576	100 00%	106,936	100.00%	*21.*
22.	1101-1200	-	-	581	99.66%	131,764	93.78%	-	-	576	100 00%	106,936	100.00%	*22.*
23.	1201-1300	-	-	581	99.66%	131,764	93.78%	-	-	576	100 00%	106,936	100.00%	*23.*
24.	1301-1400	-	-	581	99.66%	131,764	93.78%	-	-	576	100 00%	106,936	100.00%	*24.*
25.	1401-1500	1	1,467	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*25.*
26.	1501-1600	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*26.*
27.	1601-1700	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*27.*
28.	1701-1800	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*28.*
29.	1801-1900	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*29.*
30.	1901-2000	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*30.*
31.	2001-2100	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*31.*
32.	2101-2200	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*32.*
33.	2201-2300	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*33.*
34.	2301-2400	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*34.*
35.	2401-2500	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*35.*
36.	2501-2600	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*36.*
37.	2601-2700	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*37.*
38.	2701-2800	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*38.*
39.	2801-2900	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*39.*
40.	2901-3000	-	-	582	99.83%	133,231	94.82%	-	-	576	100 00%	106,936	100.00%	*40.*
41.	Over 3000	1	7,277	583	100.00%	140,508	100.00%	-	-	576	100 00%	106,936	100.00%	*41.*
		Average Number of Customers:		97				Average Number of Customers:		96				
		Average Load:		241	kW per bill			Average Load:		186	kW per bill			
		Median Load:		216	kW per bill			Median Load:		168	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-32 TOU LARGE (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				B LLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF B LLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	*1.*
2.	1-10	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	*2.*
3.	11-20	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	*3.*
4.	21-30	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	*4.*
5.	31-40	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	*5.*
6.	41-50	-	-	-	0.00%	-	0.00%	1	49	1	0.26%	49	0.01%	*6.*
7.	51-60	-	-	-	0.00%	-	0.00%	1	54	2	0.51%	103	0.03%	*7.*
8.	61-70	-	-	-	0.00%	-	0.00%	-	-	2	0.51%	103	0.03%	*8.*
9.	71-80	-	-	-	0.00%	-	0.00%	-	-	2	0.51%	103	0.03%	*9.*
10.	81-90	1	83	1	0.27%	83	0.02%	-	-	2	0.51%	103	0.03%	*10.*
11.	91-100	1	92	2	0.53%	175	0.05%	1	94	3	0.77%	196	0.06%	*11.*
12.	101-200	-	-	2	0.53%	175	0.05%	3	516	6	1.54%	712	0.21%	*12.*
13.	201-300	5	1,430	7	1.87%	1,606	0.45%	7	1,840	13	3.33%	2,553	0.74%	*13.*
14.	301-400	16	5,791	23	6.15%	7,397	2.06%	39	14,267	52	13.33%	16,820	4.86%	*14.*
15.	401-500	55	24,919	78	20.86%	32,316	8.99%	62	27,735	114	29.23%	44,555	12.88%	*15.*
16.	501-600	33	18,286	111	29.68%	50,602	14.07%	29	16,386	143	36.67%	60,941	17.62%	*16.*
17.	601-700	38	24,577	149	39.84%	75,179	20.91%	62	40,312	205	52.56%	101,253	29.28%	*17.*
18.	701-800	55	40,721	204	54.55%	115,900	32.23%	44	31,812	249	63.85%	133,065	38.48%	*18.*
19.	801-900	44	36,995	248	66.31%	152,895	42.52%	37	31,190	286	73.33%	164,255	47.50%	*19.*
20.	901-1000	28	26,289	276	73.80%	179,184	49.83%	18	16,739	304	77.95%	180,994	52.34%	*20.*
21.	1001-1100	14	14,738	290	77.54%	193,922	53.93%	1	1,099	305	78.21%	182,093	52.66%	*21.*
22.	1101-1200	4	4,597	294	78.61%	198,519	55.21%	10	11,684	315	80.77%	193,777	56.04%	*22.*
23.	1201-1300	8	10,173	302	80.75%	208,692	58.04%	8	9,805	323	82.82%	203,582	58.87%	*23.*
24.	1301-1400	4	5,412	306	81.82%	214,104	59.55%	4	5,461	327	83.85%	209,044	60.45%	*24.*
25.	1401-1500	6	8,712	312	83.42%	222,816	61.97%	7	10,236	334	85.64%	219,280	63.41%	*25.*
26.	1501-1600	1	1,540	313	83.69%	224,356	62.40%	2	3,081	336	86.15%	222,360	64.30%	*26.*
27.	1601-1700	6	9,744	319	85.29%	234,100	65.11%	7	11,334	343	87.95%	233,694	67.58%	*27.*
28.	1701-1800	7	12,310	326	87.17%	246,410	68.53%	5	8,802	348	89.23%	242,496	70.12%	*28.*
29.	1801-1900	4	7,276	330	88.24%	253,686	70.55%	-	-	348	89.23%	242,496	70.12%	*29.*
30.	1901-2000	11	21,864	341	91.18%	275,550	76.64%	22	43,325	370	94.87%	285,821	82.65%	*30.*
31.	2001-2100	3	6,126	344	91.98%	281,676	78.34%	1	2,050	371	95.13%	287,871	83.24%	*31.*
32.	2101-2200	6	12,929	350	93.58%	294,605	81.94%	-	-	371	95.13%	287,871	83.24%	*32.*
33.	2201-2300	4	8,977	354	94.65%	303,582	84.43%	1	2,232	372	95.38%	290,103	83.89%	*33.*
34.	2301-2400	4	9,452	358	95.72%	313,034	87.06%	6	14,376	378	96.92%	304,479	88.05%	*34.*
35.	2401-2500	1	2,419	359	95.99%	315,453	87.73%	-	-	378	96.92%	304,479	88.05%	*35.*
36.	2501-2600	1	2,534	360	96.26%	317,987	88.44%	-	-	378	96.92%	304,479	88.05%	*36.*
37.	2601-2700	1	2,690	361	96.52%	320,677	89.19%	-	-	378	96.92%	304,479	88.05%	*37.*
38.	2701-2800	4	10,962	365	97.59%	331,639	92.23%	1	2,736	379	97.18%	307,215	88.84%	*38.*
39.	2801-2900	4	11,407	369	98.66%	343,046	95.41%	1	2,816	380	97.44%	310,031	89.65%	*39.*
40.	2901-3000	1	2,995	370	98.93%	346,041	96.24%	1	2,930	381	97.69%	312,961	90.50%	*40.*
41.	Over 3000	4	13,518	374	100.00%	359,559	100.00%	9	32,852	390	100.00%	345,813	100.00%	*41.*
		Average Number of Customers:		62				Average Number of Customers:		65				
		Average Load:		961	kW per bill			Average Load:		887	kW per bill			
		Median Load:		758	kW per bill			Median Load:		685	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-34, E-34 Primary, E-34 Transmission (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						W NTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				B LLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF B LLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0 00%	-	0.00%	*1.*
2.	1-1000	1	111	1	0.97%	111	0.02%	-	-	-	0 00%	-	0.00%	*2.*
3.	1001-1500	-	-	1	0.97%	111	0.02%	-	-	-	0 00%	-	0.00%	*3.*
4.	1501-2000	1	2,000	2	1.94%	2,111	0.35%	2	3,126	2	1 80%	3,126	0.52%	*4.*
5.	2001-2250	-	-	2	1.94%	2,111	0.35%	-	-	2	1 80%	3,126	0.52%	*5.*
6.	2251-2500	2	4,857	4	3.88%	6,968	1.15%	-	-	2	1 80%	3,126	0.52%	*6.*
7.	2500-2750	2	5,249	6	5.83%	12,217	2.02%	4	10,338	6	5.41%	13,464	2.25%	*7.*
8.	2751-3000	1	2,880	7	6.80%	15,097	2.50%	5	14,793	11	9 91%	28,257	4.72%	*8.*
9.	3001-3250	4	12,354	11	10.68%	27,451	4.55%	7	21,942	18	16 22%	50,199	8.38%	*9.*
10.	3251-3500	1	3,283	12	11.65%	30,734	5.09%	12	41,127	30	27 03%	91,326	15.24%	*10.*
11.	3501-3750	11	39,892	23	22.33%	70,626	11.71%	3	10,848	33	29.73%	102,174	17.05%	*11.*
12.	3751-4000	4	15,572	27	26.21%	86,198	14.29%	12	47,514	45	40 54%	149,688	24.98%	*12.*
13.	4001-4250	6	24,808	33	32.04%	111,006	18.40%	2	8,424	47	42 34%	158,112	26.39%	*13.*
14.	4251-4500	7	30,477	40	38.83%	141,483	23.45%	7	31,248	54	48 65%	189,360	31.60%	*14.*
15.	4501-4750	2	9,119	42	40.78%	150,602	24.96%	-	-	54	48 65%	189,360	31.60%	*15.*
16.	4751-5000	8	38,624	50	48 54%	189,226	31.36%	5	24,268	59	53.15%	213,628	35.65%	*16.*
17.	5001-5500	7	37,095	57	55 34%	226,321	37.51%	8	42,472	67	60 36%	256,100	42.74%	*17.*
18.	5501-6000	11	62,188	68	66.02%	288,509	47.82%	18	103,408	85	76 58%	359,508	60.00%	*18.*
19.	6001-6500	4	25,300	72	69.90%	313,809	52.01%	2	12,384	87	78 38%	371,892	62.07%	*19.*
20.	6501-7000	7	46,622	79	76.70%	360,431	59.74%	1	6,682	88	79 28%	378,574	63.18%	*20.*
21.	7001-7500	5	36,454	84	81.55%	396,885	65.78%	6	44,706	94	84 68%	423,280	70.64%	*21.*
22.	7501-8000	1	7,947	85	82.52%	404,832	67.10%	-	-	94	84 68%	423,280	70.64%	*22.*
23.	8001-8500	4	33,195	89	86.41%	438,027	72.60%	2	16,560	96	86.49%	439,840	73.41%	*23.*
24.	8501-9000	-	-	89	86.41%	438,027	72.60%	2	17,568	98	88 29%	457,408	76.34%	*24.*
25.	9001-9500	1	9,314	90	87 38%	447,341	74.14%	1	9,216	99	89.19%	466,624	77.88%	*25.*
26.	9501-10000	-	-	90	87 38%	447,341	74.14%	4	38,880	103	92.79%	505,504	84.36%	*26.*
27.	10001-12500	9	97,838	99	96.12%	545,179	90.36%	8	93,684	111	100 00%	599,188	100.00%	*27.*
28.	12501-15000	3	42,965	102	99.03%	588,144	97.48%	-	-	111	100 00%	599,188	100.00%	*28.*
29.	15001-17500	1	15,198	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*29.*
30.	17501-20000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*30.*
31.	20001-22500	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*31.*
32.	22501-25000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*32.*
33.	25001-27500	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*33.*
34.	27501-30000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*34.*
35.	30001-32500	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*35.*
36.	32501-35000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*36.*
37.	35001-37500	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*37.*
38.	37501-40000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*38.*
39.	40001-60000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*39.*
40.	60001-80000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*40.*
41.	Over 80000	-	-	103	100.00%	603,342	100.00%	-	-	111	100 00%	599,188	100.00%	*41.*
		Average Number of Customers:		17				Average Number of Customers:		19				
		Average Load:		5,858	kW per bill			Average Load:		5,398	kW per bill			
		Median Load:		5,060	kW per bill			Median Load:		4,800	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-35, E-35 Primary, E-35 Transmission (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				B LLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF B LLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF B LLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	-	-	-	0.00%	-	0 00%	-	-	-	0.00%	-	0.00%	*1.*
2.	1-1000	10	3,740	10	4.52%	3,740	0 30%	8	4,672	8	3.64%	4,672	0.40%	*2.*
3.	1001-1500	9	11,606	19	8.60%	15,346	1 23%	6	6,756	14	6.36%	11,428	0.98%	*3.*
4.	1501-2000	2	3,168	21	9.50%	18,514	1.48%	4	7,024	18	8.18%	18,452	1.58%	*4.*
5.	2001-2250	-	-	21	9.50%	18,514	1.48%	8	16,928	26	11.82%	35,380	3.02%	*5.*
6.	2251-2500	2	4,606	23	10.41%	23,120	1 85%	9	21,232	35	15.91%	56,612	4.84%	*6.*
7.	2500-2750	7	18,227	30	13.57%	41,347	3 30%	10	26,597	45	20.45%	83,209	7.11%	*7.*
8.	2751-3000	5	14,168	35	15.84%	55,515	4.43%	3	8,596	48	21.82%	91,805	7.85%	*8.*
9.	3001-3250	23	72,280	58	26.24%	127,795	10 20%	24	75,176	72	32.73%	166,981	14.28%	*9.*
10.	3251-3500	13	43,860	71	32.13%	171,655	13.70%	13	43,989	85	38.64%	210,970	18.04%	*10.*
11.	3501-3750	14	50,646	85	38.46%	222,301	17.75%	12	43,385	97	44.09%	254,355	21.75%	*11.*
12.	3751-4000	13	50,302	98	44.34%	272,603	21.76%	9	34,442	106	48.18%	288,797	24.69%	*12.*
13.	4001-4250	7	28,732	105	47.51%	301,335	24.06%	3	12,280	109	49.55%	301,077	25.74%	*13.*
14.	4251-4500	2	8,756	107	48.42%	310,091	24.76%	3	13,152	112	50.91%	314,229	26.87%	*14.*
15.	4501-4750	3	13,731	110	49.77%	323,822	25.85%	11	50,373	123	55.91%	364,602	31.17%	*15.*
16.	4751-5000	6	29,279	116	52.49%	353,101	28.19%	3	14,721	126	57.27%	379,323	32.43%	*16.*
17.	5001-5500	12	63,418	128	57.92%	416,519	33.25%	7	36,949	133	60.45%	416,272	35.59%	*17.*
18.	5501-6000	12	68,737	140	63.35%	485,256	38.74%	20	113,309	153	69.55%	529,581	45.28%	*18.*
19.	6001-6500	6	37,102	146	66.06%	522,358	41.70%	9	56,404	162	73.64%	585,985	50.10%	*19.*
20.	6501-7000	20	135,272	166	75.11%	657,630	52 50%	9	60,236	171	77.73%	646,221	55.25%	*20.*
21.	7001-7500	6	44,084	172	77.83%	701,714	56 02%	10	72,436	181	82.27%	718,657	61.44%	*21.*
22.	7501-8000	10	77,322	182	82.35%	779,036	62.19%	15	116,514	196	89.09%	835,171	71.40%	*22.*
23.	8001-8500	3	24,882	185	83.71%	803,918	64.18%	-	-	196	89.09%	835,171	71.40%	*23.*
24.	8501-9000	5	44,189	190	85.97%	848,107	67.71%	5	43,980	201	91.36%	879,151	75.16%	*24.*
25.	9001-9500	7	64,759	197	89.14%	912,866	72 88%	1	9,100	202	91.82%	888,251	75.94%	*25.*
26.	9501-10000	4	39,234	201	90.95%	952,100	76 01%	-	-	202	91.82%	888,251	75.94%	*26.*
27.	10001-12500	6	68,581	207	93.67%	1,020,681	81.48%	2	24,499	204	92.73%	912,750	78.04%	*27.*
28.	12501-15000	3	40,506	210	95.02%	1,061,187	84.72%	4	51,581	208	94.55%	964,331	82.45%	*28.*
29.	15001-17500	4	63,510	214	96.83%	1,124,697	89.79%	6	91,200	214	97.27%	1,055,531	90.24%	*29.*
30.	17501-20000	7	127,935	221	100.00%	1,252,632	100.00%	6	114,100	220	100.00%	1,169,631	100.00%	*30.*
31.	20001-22500	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*31.*
32.	22501-25000	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*32.*
33.	25001-27500	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*33.*
34.	27501-30000	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*34.*
35.	30001-32500	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*35.*
36.	32501-35000	-	-	221	100.00%	1,252,632	100 00%	-	-	220	100.00%	1,169,631	100.00%	*36.*
37.	35001-37500	-	-	221	100.00%	1,252,632	100 00%	-	-	220	100.00%	1,169,631	100.00%	*37.*
38.	37501-40000	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*38.*
39.	40001-60000	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*39.*
40.	60001-80000	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*40.*
41.	Over 80000	-	-	221	100.00%	1,252,632	100.00%	-	-	220	100.00%	1,169,631	100.00%	*41.*
		Average Number of Customers:		37				Average Number of Customers:		37				
		Average Load:		5,668	kW per bill			Average Load:		5,317	kW per bill			
		Median Load:		4,752	kW per bill			Median Load:		4,344	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-36 XL**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		LOAD		
Line No.	BLOCK (kW) *(A)*	NUMBER OF B LLS BY BLOCK *(B)*	LOAD kW BY BLOCK *(C)*	Number *(D)*	% of Total *(E)*	Amount (kW) *(F)*	% of Total *(G)*	*Line No.*
1.								*1.*
2.		B LLING DETERMINANTS FOR E-36 CUSTOMERS ARE NOT UTILIZED						*2.*
3.		IN REVENUE REQUIREMENT CALCULATIONS						*3.*
4.								*4.*
5.								*5.*
6.								*6.*
7.								*7.*
8.								*8.*
9.								*9.*
10.								*10.*
11.								*11.*
12.								*12.*
13.								*13.*
14.								*14.*
15.								*15.*
16.								*16.*
17.								*17.*
18.								*18.*
19.								*19.*
20.								*20.*
21.								*21.*
22.								*22.*
23.								*23.*
24.								*24.*
25.								*25.*
26.								*26.*
27.								*27.*
28.								*28.*
29.								*29.*
30.								*30.*
31.								*31.*
32.								*32.*
33.								*33.*
34.								*34.*
35.								*35.*
36.								*36.*
37.								*37.*
38.								*38.*
39.								*39.*
40.								*40.*
41.								*41.*

Average Number of Customers:
Average Load: kW per bill
Median Load: kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **GS-SCHL SCHOOLS TOU LARGE**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	-	-	-	0.00%	-	0.00%	1	-	1	0.38%	-	0 00%	*1.*
2.	1-10	-	-	-	0.00%	-	0.00%	-	-	1	0.38%	-	0 00%	*2.*
3.	11-20	-	-	-	0.00%	-	0.00%	3	46	4	1.52%	46	0 04%	*3.*
4.	21-30	-	-	-	0.00%	-	0 00%	2	46	6	2.27%	92	0 09%	*4.*
5.	31-40	-	-	-	0.00%	-	0 00%	-	-	6	2.27%	92	0 09%	*5.*
6.	41-50	-	-	-	0.00%	-	0 00%	5	228	11	4.17%	320	0 30%	*6.*
7.	51-60	-	-	-	0.00%	-	0 00%	1	59	12	4.55%	379	0 36%	*7.*
8.	61-70	-	-	-	0 00%	-	0 00%	3	202	15	5.68%	581	0 55%	*8.*
9.	71-80	-	-	-	0.00%	-	0 00%	3	222	18	6.82%	803	0.76%	*9.*
10.	81-90	-	-	-	0.00%	-	0 00%	1	86	19	7.20%	889	0 85%	*10.*
11.	91-100	-	-	-	0.00%	-	0 00%	1	95	20	7.58%	984	0 94%	*11.*
12.	101-200	3	460	3	1.27%	460	0 35%	13	1,871	33	12.50%	2,855	2.71%	*12.*
13.	201-300	2	464	5	2.12%	924	0.71%	41	10,521	74	28.03%	13,376	12.71%	*13.*
14.	301-400	28	10,199	33	13.98%	11,123	8 56%	52	18,350	126	47.73%	31,726	30.16%	*14.*
15.	401-500	56	25,215	89	37.71%	36,338	27 98%	84	37,976	210	79.55%	69,702	66 25%	*15.*
16.	501-600	68	37,481	157	66 53%	73,819	56 84%	26	14,402	236	89.39%	84,104	79 94%	*16.*
17.	601-700	46	29,521	203	86 02%	103,340	79 57%	15	9,835	251	95.08%	93,939	89 29%	*17.*
18.	701-800	18	13,441	221	93.64%	116,781	89 92%	7	5,193	258	97.73%	99,132	94 23%	*18.*
19.	801-900	11	9,399	232	98.31%	126,180	97.15%	3	2,518	261	98.86%	101,650	96 62%	*19.*
20.	901-1000	4	3,696	236	100.00%	129,876	100 00%	-	-	261	98.86%	101,650	96 62%	*20.*
21.	1001-1100	-	-	236	100.00%	129,876	100 00%	1	1,006	262	99.24%	102,656	97 58%	*21.*
22.	1101-1200	-	-	236	100.00%	129,876	100 00%	1	1,157	263	99.62%	103,813	98 68%	*22.*
23.	1201-1300	-	-	236	100.00%	129,876	100 00%	-	-	263	99.62%	103,813	98 68%	*23.*
24.	1301-1400	-	-	236	100 00%	129,876	100 00%	1	1,393	264	100.00%	105,206	100 00%	*24.*
25.	1401-1500	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*25.*
26.	1501-1600	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*26.*
27.	1601-1700	-	-	236	100.00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*27.*
28.	1701-1800	-	-	236	100.00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*28.*
29.	1801-1900	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*29.*
30.	1901-2000	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*30.*
31.	2001-2100	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*31.*
32.	2101-2200	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*32.*
33.	2201-2300	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*33.*
34.	2301-2400	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*34.*
35.	2401-2500	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*35.*
36.	2501-2600	-	-	236	100.00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*36.*
37.	2601-2700	-	-	236	100.00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*37.*
38.	2701-2800	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*38.*
39.	2801-2900	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*39.*
40.	2901-3000	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*40.*
41.	Over 3000	-	-	236	100 00%	129,876	100 00%	-	-	264	100.00%	105,206	100 00%	*41.*
		Average Number of Customers:		39				Average Number of Customers:		44				
		Average Load:		550	kW per bill			Average Load:		399	kW per bill			
		Median Load:		545	kW per bill			Median Load:		408	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **GS-SCHM SCHOOLS TOU MEDIUM**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	2	-	2	0.16%	-	0.00%	18	-	18	1.27%	-	0 00%	*1.*
2.	1-10	6	16	8	0.64%	16	0.01%	36	197	54	3.80%	197	0 07%	*2.*
3.	11-20	4	64	12	0.95%	80	0 03%	24	366	78	5.49%	563	0 20%	*3.*
4.	21-30	11	281	23	1.83%	361	0.12%	18	453	96	6.76%	1,016	0 36%	*4.*
5.	31-40	10	345	33	2.62%	706	0 24%	29	1,064	125	8.80%	2,080	0.74%	*5.*
6.	41-50	15	708	48	3.81%	1,414	0.48%	33	1,499	158	11.12%	3,579	1 28%	*6.*
7.	51-60	18	1,033	66	5.24%	2,447	0 82%	21	1,176	179	12.60%	4,755	1.70%	*7.*
8.	61-70	14	895	80	6.35%	3,342	1.12%	49	3,197	228	16.05%	7,952	2 84%	*8.*
9.	71-80	9	691	89	7.07%	4,033	1 36%	34	2,567	262	18.44%	10,519	3.76%	*9.*
10.	81-90	16	1,384	105	8.34%	5,417	1.82%	31	2,652	293	20.62%	13,171	4.70%	*10.*
11.	91-100	30	2,855	135	10.72%	8,272	2.78%	26	2,476	319	22.45%	15,647	5 59%	*11.*
12.	101-200	334	50,888	469	37.25%	59,160	19 89%	476	74,254	795	55.95%	89,901	32.10%	*12.*
13.	201-300	451	112,196	920	73.07%	171,356	57 61%	406	98,740	1,201	84.52%	188,641	67 36%	*13.*
14.	301-400	248	84,565	1,168	92.77%	255,921	86 04%	130	44,752	1,331	93.67%	233,393	83 35%	*14.*
15.	401-500	78	34,318	1,246	98.97%	290,239	97 58%	59	25,862	1,390	97.82%	259,255	92 58%	*15.*
16.	501-600	9	4,734	1,255	99.68%	294,973	99.17%	18	9,656	1,408	99.09%	268,911	96 03%	*16.*
17.	601-700	4	2,479	1,259	100.00%	297,452	100 00%	7	4,500	1,415	99.58%	273,411	97 64%	*17.*
18.	701-800	-	-	1,259	100.00%	297,452	100 00%	1	707	1,416	99.65%	274,118	97 89%	*18.*
19.	801-900	-	-	1,259	100.00%	297,452	100 00%	2	1,714	1,418	99.79%	275,832	98 50%	*19.*
20.	901-1000	-	-	1,259	100.00%	297,452	100 00%	1	990	1,419	99.86%	276,822	98 85%	*20.*
21.	1001-1100	-	-	1,259	100 00%	297,452	100 00%	-	-	1,419	99.86%	276,822	98 85%	*21.*
22.	1101-1200	-	-	1,259	100 00%	297,452	100 00%	-	-	1,419	99.86%	276,822	98 85%	*22.*
23.	1201-1300	-	-	1,259	100 00%	297,452	100 00%	1	1,216	1,420	99.93%	278,038	99 29%	*23.*
24.	1301-1400	-	-	1,259	100 00%	297,452	100 00%	-	-	1,420	99.93%	278,038	99 29%	*24.*
25.	1401-1500	-	-	1,259	100 00%	297,452	100 00%	-	-	1,420	99.93%	278,038	99 29%	*25.*
26.	1501-1600	-	-	1,259	100 00%	297,452	100 00%	-	-	1,420	99.93%	278,038	99 29%	*26.*
27.	1601-1700	-	-	1,259	100.00%	297,452	100 00%	-	-	1,420	99.93%	278,038	99 29%	*27.*
28.	1701-1800	-	-	1,259	100.00%	297,452	100 00%	-	-	1,420	99.93%	278,038	99 29%	*28.*
29.	1801-1900	-	-	1,259	100 00%	297,452	100 00%	-	-	1,420	99.93%	278,038	99 29%	*29.*
30.	1901-2000	-	-	1,259	100 00%	297,452	100 00%	1	1,994	1,421	100.00%	280,032	100 00%	*30.*
31.	2001-2100	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*31.*
32.	2101-2200	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*32.*
33.	2201-2300	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*33.*
34.	2301-2400	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*34.*
35.	2401-2500	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*35.*
36.	2501-2600	-	-	1,259	100.00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*36.*
37.	2601-2700	-	-	1,259	100.00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*37.*
38.	2701-2800	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*38.*
39.	2801-2900	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*39.*
40.	2901-3000	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*40.*
41.	Over 3000	-	-	1,259	100 00%	297,452	100 00%	-	-	1,421	100.00%	280,032	100 00%	*41.*
		Average Number of Customers:		210				Average Number of Customers:		237				
		Average Load:		236	kW per bill			Average Load:		197	kW per bill			
		Median Load:		234	kW per bill			Median Load:		187	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-5
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2022

RATE SCHEDULE: **E-221 and E-221-8T**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	*Line No.*
	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*	*(G)*	*(H)*	*(I)*	*(J)*	*(K)*	*(L)*	*(M)*	
1.	0	820	-	820	9 99%	-	0.00%	1,173	-	1,173	14.35%	-	0.00%	*1.*
2.	1-10	1,510	7,705	2,330	28 39%	7,705	1.07%	1,468	7,554	2,641	32.31%	7,554	0.99%	*2.*
3.	11-20	831	12,961	3,161	38 52%	20,666	2.86%	723	11,209	3,364	41.15%	18,763	2.47%	*3.*
4.	21-30	676	17,138	3,837	46.76%	37,804	5.24%	587	14,876	3,951	48.33%	33,639	4.43%	*4.*
5.	31-40	467	16,437	4,304	52.45%	54,241	7.51%	400	14,336	4,351	53.22%	47,975	6.31%	*5.*
6.	41-50	360	16,259	4,664	56.84%	70,500	9.77%	293	13,295	4,644	56.81%	61,270	8.06%	*6.*
7.	51-60	322	18,028	4,986	60.76%	88,528	12.26%	326	18,204	4,970	60.80%	79,474	10.46%	*7.*
8.	61-70	249	16,216	5,235	63.79%	104,744	14.51%	216	14,130	5,186	63.44%	93,604	12.32%	*8.*
9.	71-80	202	15,189	5,437	66 26%	119,933	16.61%	191	14,445	5,377	65.77%	108,049	14.22%	*9.*
10.	81-90	164	14,009	5,601	68 25%	133,942	18.55%	163	13,920	5,540	67.77%	121,969	16.05%	*10.*
11.	91-100	202	19,300	5,803	70.72%	153,242	21.23%	188	17,981	5,728	70.07%	139,950	18.42%	*11.*
12.	101-200	1,432	206,996	7,235	88.17%	360,238	49.90%	1,319	187,799	7,047	86.20%	327,749	43.14%	*12.*
13.	201-300	523	127,589	7,758	94 54%	487,827	67.57%	547	133,432	7,594	92.89%	461,181	60.70%	*13.*
14.	301-400	199	67,541	7,957	96 97%	555,368	76.93%	280	95,067	7,874	96.32%	556,248	73.21%	*14.*
15.	401-500	93	41,242	8,050	98.10%	596,610	82.64%	101	45,285	7,975	97.55%	601,533	79.17%	*15.*
16.	501-600	51	28,448	8,101	98.72%	625,058	86.58%	82	44,607	8,057	98.56%	646,140	85.04%	*16.*
17.	601-700	42	27,063	8,143	99 23%	652,121	90.33%	37	23,967	8,094	99.01%	670,107	88.19%	*17.*
18.	701-800	11	8,138	8,154	99 37%	660,259	91.46%	15	11,231	8,109	99.19%	681,338	89.67%	*18.*
19.	801-900	6	5,185	8,160	99.44%	665,444	92.18%	15	12,881	8,124	99.38%	694,219	91.37%	*19.*
20.	901-1000	20	18,996	8,180	99 68%	684,440	94.81%	16	14,939	8,140	99.57%	709,158	93.33%	*20.*
21.	1001-1100	9	9,470	8,189	99.79%	693,910	96.12%	13	13,630	8,153	99.73%	722,788	95.13%	*21.*
22.	1101-1200	3	3,473	8,192	99 83%	697,383	96.60%	4	4,660	8,157	99.78%	727,448	95.74%	*22.*
23.	1201-1300	2	2,567	8,194	99 85%	699,950	96.96%	1	1,284	8,158	99.79%	728,732	95.91%	*23.*
24.	1301-1400	-	-	8,194	99 85%	699,950	96.96%	3	3,957	8,161	99.83%	732,689	96.43%	*24.*
25.	1401-1500	-	-	8,194	99 85%	699,950	96.96%	1	1,422	8,162	99.84%	734,111	96.62%	*25.*
26.	1501-1600	1	1,514	8,195	99 87%	701,464	97.17%	3	4,665	8,165	99.88%	738,776	97.23%	*26.*
27.	1601-1700	1	1,656	8,196	99 88%	703,120	97.40%	2	3,280	8,167	99.90%	742,056	97.66%	*27.*
28.	1701-1800	3	5,172	8,199	99 91%	708,292	98.11%	-	-	8,167	99.90%	742,056	97.66%	*28.*
29.	1801-1900	3	5,595	8,202	99 95%	713,887	98.89%	4	7,410	8,171	99.95%	749,466	98.64%	*29.*
30.	1901-2000	2	3,906	8,204	99 98%	717,793	99.43%	1	1,920	8,172	99.96%	751,386	98.89%	*30.*
31.	2001-2100	2	4,112	8,206	100 00%	721,905	100.00%	-	-	8,172	99.96%	751,386	98.89%	*31.*
32.	2101-2200	-	-	8,206	100 00%	721,905	100.00%	-	-	8,172	99.96%	751,386	98.89%	*32.*
33.	2201-2300	-	-	8,206	100 00%	721,905	100.00%	1	2,234	8,173	99.98%	753,620	99.19%	*33.*
34.	2301-2400	-	-	8,206	100 00%	721,905	100.00%	-	-	8,173	99.98%	753,620	99.19%	*34.*
35.	2401-2500	-	-	8,206	100 00%	721,905	100.00%	-	-	8,173	99.98%	753,620	99.19%	*35.*
36.	2501-2600	-	-	8,206	100 00%	721,905	100.00%	1	2,512	8,174	99.99%	756,132	99.52%	*36.*
37.	2601-2700	-	-	8,206	100 00%	721,905	100.00%	-	-	8,174	99.99%	756,132	99.52%	*37.*
38.	2701-2800	-	-	8,206	100 00%	721,905	100.00%	-	-	8,174	99.99%	756,132	99.52%	*38.*
39.	2801-2900	-	-	8,206	100 00%	721,905	100.00%	-	-	8,174	99.99%	756,132	99.52%	*39.*
40.	2901-3000	-	-	8,206	100 00%	721,905	100.00%	-	-	8,174	99.99%	756,132	99.52%	*40.*
41.	Over 3000	-	-	8,206	100 00%	721,905	100.00%	1	3,672	8,175	100.00%	759,804	100.00%	*41.*
		Average Number of Customers:		1,368				Average Number of Customers:		1,363				
		Average Load:		88	kW per bill			Average Load:		93	kW per bill			
		Median Load:		36	kW per bill			Median Load:		34	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTE: kWh does not include adjustments for customer annualization and weather normalization.
NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY

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CLASSIFICATION OF SERVICES – NO CHANGE

RESIDENTIAL

FROZEN/REVISED	Legacy E-12	Energy-Only – On-Site Distributed Generation
FROZEN/REVISED	Legacy ECT-1R	Time-of-Use with Demand Charge – On-Site Distributed Gen.
FROZEN/REVISED	Legacy ECT-2	Time-of-Use with Demand Charge (12 pm to 7 pm) – On-Site DG
FROZEN/REVISED	Legacy ET-1	Time-of-Use – On-Site Distributed Generation
FROZEN/REVISED	Legacy ET-2	Time-of-Use (12 pm to 7 pm) – On-Site Distributed Generation
REVISED	R-1	Fixed Energy Charge
FROZEN/REVISED	R-2	Saver Choice Plus – Time-of-Use with Demand Charge
REVISED	R-EV	Electric Vehicle Time-of-Use Energy Charges
REVISED	R-TECH	Technology Time-of-Use with Demand
REVISED	R-3	Time-of-Use 4PM to 7PM Weekdays with Demand Charge
REVISED	TOU-E	Time-of-Use 4PM to 7PM Weekdays

GENERAL SERVICE

REVISED	E-30	Extra Small Unmetered
REVISED	E-32 L	Large General Service (401 kW +)
REVISED	E-32 M	Medium General Service (101 kW – 400 kW)
REVISED	E-32 S	Small General Service (21 kW – 100 kW)
REVISED	E-32 XS	Extra Small General Service (0 kW – 20 kW)
REVISED	E-32 XS D	Extra Small General Service with Demand (0 kW – 20 kW)
REVISED	E-32TOU L	Time-of-Use – Large General Service (401 kW +)
REVISED	E-32TOU M	Time-of-Use – Medium General Service (101 kW – 400 kW)
REVISED	E-32TOU S	Time-of-Use – Small General Service (21 kW – 100 kW)
REVISED	E-32TOU XS	Time-of-Use – Extra Small General Service (0 kW – 20 kW)
REVISED	E-34	Extra Large General Service
REVISED	E-35	Extra Large General Service – Time-Of-Use
REVISED	XHLF	Extra Large General Service – Extra High Load Factor

CLASSIFIED

REVISED	E-20	Time-of-Use for Religious Houses of Worship
REVISED	E-32 L SP	Large General Service (401 kW +) with Storage Pilot
REVISED	E-36 XL	Station Use Service XL
REVISED	E-45	Dusk to Dawn Lighting Service
REVISED/FROZEN	E-47	Dusk to Dawn Lighting Service
REVISED/FROZEN	E-58	Street Lighting Service
REVISED	E-59	Government Owned Street Lighting Systems
REVISED	E-67	Municipal Lighting Service - City of Phoenix
REVISED	E-68	Street Lighting Service
REVISED	E-221	Water Pumping Service
REVISED	E-221 AG	Agricultural Water Pumping Service
REVISED	E-221 AG TOU	Time-of-Use – Agricultural Water Pumping Service
REVISED	E-221-8T	Water Pumping Service – Time-of-Use
REVISED	GS-SCHOOLS L	Time-of-Use – Elementary and Secondary Schools (401kW +)
REVISED	GS-SCHOOLS M	Time-of-Use – Elementary and Secondary Schools (0kW – 400 kW)

ARIZONA PUBLIC SERVICE COMPANY

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ADJUSTMENTS

REVISED	DSMAC-1	Demand Side Management Adjustment Charge
CANCELED	EIS	Environmental Improvement Surcharge
CANCELED	LFCR	Lost Fixed Cost Recovery Mechanism
REVISED	PSA-1	Power Supply Adjustment
NO CHANGE	RCDAC-1	Returning Customer Direct Access Charge
REVISED	REAC-1	Renewable Energy Adjustment Charge
NO CHANGE	SDR	Self-Directed Renewable Resources
REVISED	TCA-1	Transmission Cost Adjustment
NO CHANGE	TEAM	Tax Expense Adjustment Mechanism

RIDERS

RESIDENTIAL		
NO CHANGE	CPP-RES	Critical Peak Pricing – Residential
REVISED	E-3	Limited Income Energy Support
FROZEN/REVISED	Legacy E-3	Legacy Limited Income Energy Support
REVISED	E-4	Limited Income Medical Care Equipment Support
FROZEN/REVISED	Legacy E-4	Legacy Limited Income Medical Care Equipment Support
FROZEN/NO CHANGE	Legacy EPR-6	Legacy Net Metering
FROZEN/NO CHANGE	Legacy LFCR-DG	Legacy Adjustment for Distributed Generation
NO CHANGE	GPS-1	Green Power Block Schedule
NO CHANGE	GPS-2	Green Power Percent Schedule
NO CHANGE	GPS-3	Green Power Block Schedule for Special Events
REVISED	RCP	Resource Comparison Proxy Export Rate
GENERAL SERVICE		
REVISED	AG-X	Alternative Generation –General Service
NO CHANGE	CPP-GS	Critical Peak Pricing – General Service
NO CHANGE	DCFC	Direct Current Fast Charging Pilot
NO CHANGE	EPR-6	Partial Requirements Service – On-Site Renewable DG
NO CHANGE	GPP	Green Power Partners
NO CHANGE	IRR	Interruptible Rate Rider – Extra Large General Service
REVISED	PPR	Preference Power
REVISED	SD-1	School Discount
FROZEN/REVISED	SGSP	Schools and Government Solar Program
CLASSIFIED		
REVISED	E-56	Partial Requirements Service
NO CHANGE	E-56R	Partial Requirements Service – Renewable
NO CHANGE	EPR-2	Partial Requirements Service – Qualified Facilities of 100 kW or less

RIDERS - PENDING

PENDING	GS-EV	General Service – Electric Vehicle

ARIZONA PUBLIC SERVICE COMPANY

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PLANS OF ADMINISTRATION*

REVISED	DSMAC	Plan of Administration for the Demand Side Management Adjustment Charge
CANCELED	EIS	Plan of Administration for the Environmental Improvement Surcharge
CANCELED	LFCR	Plan of Administration for the Lost Fixed Cost Recovery
REVISED	PSA	Plan of Administration for the Power Supply Adjustment
NO CHANGE	RCDAC	Plan of Administration for the Returning Customer Direct Access Charge
NO CHANGE	RCP	Plan of Administration for the Resource Comparison Proxy
REVISED	REAC	Plan of Administration for the Renewable Energy Adjustment Charge
NO CHANGE	TCA	Plan of Administration for the Transmission Cost Adjustment
NO CHANGE	TEAM	Plan of Administration for the Tax Expense Adjustment Mechanism

*Plan of Administration Attachments are not included.

SERVICE SCHEDULES

REVISED	Schedule 1	Terms and Conditions for Standard Offer and Direct Access Services
NO CHANGE	Schedule 2	Terms and Conditions for Energy Purchases from Qualified Cogeneration and Small Power Production Facilities
REVISED	Schedule 3	Conditions Governing Extensions of Electric Distribution Lines and Services
NO CHANGE	Schedule 4	Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service
NO CHANGE	Schedule 5	Guidelines for Electric Curtailment
NO CHANGE	Schedule 6	Interconnection Study Services and Fees for Non-FERC Generation Facilities
NO CHANGE	Schedule 7	Electric Meter Testing and Maintenance Plan
NO CHANGE	Schedule 8	Bill Estimation
REVISED	Schedule 9	Conditions Governing Economic Incentives for the Industrial Development Plan
NO CHANGE	Schedule 10	Terms and Conditions for Direct Access
NO CHANGE	Schedule 15	Conditions Governing the Provision of Specialized Metering

NOTES:

CANCELED:	Rate schedule will no longer be offered.
FROZEN:	Rate schedule will no longer be available to new customers.
NO CHANGE:	No change to rates or language in rate schedule (footnote changes may be made).
PENDING:	Rate schedule is awaiting approval in a separate docket.
REVISED:	Rate or language changes included.

A. RESIDENTIAL SERVICE

1. Residence - Single

Residential service to a single residence covers electric service to a private residence or individually metered apartment unit, only.

Outbuildings on the same premises may be connected to the residential service meter, but only if such outbuildings form a part of the general living establishment.

2. Residence - Multiple

Residential service to two or more residences on the same premises or a residence or residences subdivided into two or more individual housekeeping apartments shall not be supplied through one meter on a Residential Service Rate Schedule.

Individual meters will be installed by the Company for each individual dwelling or housekeeping unit. If, for any reason, a separate meter is not installed for each individual dwelling or housekeeping unit, then the appropriate General Service Rate Schedule will be used for billing for the service supplied through the single meter.

3. Professional Offices or Commercial Activities in Dwellings

The supply of service under a Residential Rate Schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the energy used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters.

Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electric equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises shall be classified as non-residential and the appropriate General Service Rate Schedule shall be applied. Customer may at their option provide separate circuits so that the residential uses can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

4. Farm and Rural Residences

The Residential Service Rate Schedules are available for electric service through one meter to a farm residence, and the usual farm uses outside the dwelling unit,

but not if the use extends to operations such as canning plants, packing plants, stone quarries, ice cream manufacturing plants, stores, restaurants, tea rooms, tourist and trailer camps, gasoline stations, automobile service stations, repair shops, blacksmith shops or any other commercial or non-farming operation. In no case shall the use extend to the processing, preparing or distributing of products not raised on the same farm and in no cases shall the use extend to a hatchery, dairy, butchery, greenhouse, or any other specialized operation unless such operation is conducted solely by the farmer and is incidental to the usual farm residence uses.

Customer may at his option elect to take the entire service under the appropriate General Service Rate Schedule, or may provide separate circuits so that the residential uses, together with the usual farm uses outside the dwelling unit, can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

The Residential Service Rate Schedules are not available for any use outside the dwelling unit on a farm which is not operated by an individual owner or lessee, occupying the farm residence.

B. GENERAL SERVICE

This covers service to any establishment for any purpose not prohibited by the rate schedule or Agreement for Service.

The General Service Rate Schedules are available only when all electric service required on the premises is taken through one meter at one point of delivery, except that:

(a) General Service Rate Schedules are available for more than one point of delivery on any one premise, provided that in such event, service supplied at each point of delivery will be separately metered and separately billed.

(b) The General Service Rate Schedules will be available for service to that portion of the Customer's premises which cannot be served at the Residential Service Rate Schedule or a Classified Service Rate Schedule. Service to such portion of the premises shall be considered as service to a separate Customer, and all electric service taken therein at the General

Service Rate Schedule must be through one meter at one point of delivery.

C. CLASSIFIED SERVICE

Classified service covers service for which specific rate schedules are available, due to the nature and load characteristics of the particular business. For such service, the General Service Rate Schedule may be used, except as specifically prohibited in that Schedule, while Classified Rate Schedules are available only to those businesses complying with the specific requirements of the particular schedule.

Service supplied under a Classified Rate Schedule shall be used only for the purposes specified in such rate schedule. In the event the Company questions whether the service is being used in compliance with said rate schedule, the Customer shall have the burden of establishing such compliance to the satisfaction of the Company. In the absence of such compliance, the Company may substitute an appropriate General Service Rate Schedule.

A Customer conducting mixed operations, a part of which may be served at a Classified Rate Schedule may, at his option, elect to take the entire service under the General Service Rate Schedule or may provide separate circuits so that the classified service can be metered and billed separately at the available classified schedule, and the other uses metered and billed under the available General Service Rate Schedule.

RATE SCHEDULE LEGACY E-12
RESIDENTIAL SERVICE FOR
LEGACY ON-SITE DISTRIBUTED GENERATION

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program.

This rate schedule is frozen effective September 1, 2017. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. In the winter season, all energy used is charged at a single price. In the summer season, energy is priced in blocks by usage, with charges that increase as usage increases. This rate does not have time-of-use charges or a demand charge.

TIME PERIODS

Summer Season: May through October billing cycles
Winter Season: November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.395	per day

FROZEN

Energy Charges					
Summer			Winter		
First 400 kWh	$ 0.13213	per kWh	All kWh	$ 0.12841	per kWh
Next 400 kWh	$ 0.18914	per kWh			
Next 2200 kWh	$ 0.22158	per kWh			
Over 3000 kWh	$ 0.23639	per kWh			

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.088	per day
Metering Charge	$ 0.125	per day
Meter Reading Charge	$ 0.087	per day
Billing Charge	$ 0.095	per day

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Transmission Charge	$ 0.01097	per kWh
Delivery Charge	$ 0.03729	per kWh

Generation Charges					
Summer			Winter		
First 400 kWh	$ 0.08000	per kWh	All kWh	$ 0.07628	per kWh
Next 400 kWh	$ 0.13701	per kWh			
Next 2200 kWh	$ 0.16945	per kWh			
Over 3000 kWh	$ 0.18426	per kWh			

FROZEN

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial requirements – Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount – Legacy
Legacy E-4	Limited income medical discount – Legacy
GPS-1, GPS-2, GPS-3	Green Power

FROZEN

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar Customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule, may take service under the grandfathering program. If the interconnection is delayed by a third

party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the Customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule, but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Electric service for some Customers is measured through two meters as part of a legacy water heating or space heating program. For these Customers, readings from the two meters will be combined for measuring total energy use.

FROZEN

RATE SCHEDULE LEGACY ECT-1R
RESIDENTIAL TIME-OF-USE SERVICE
WITH DEMAND CHARGE FOR
LEGACY ON-SITE DISTRIBUTED GENERATION

FROZEN

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program that were on Rate Schedule ECT-1R prior to January 1, 2010.

This rate schedule was frozen beginning on January 1, 2010. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for this rate schedule is 9 a.m. to 9 p.m. Monday through Friday. All other hours are Off-Peak hours. The rate also varies by summer and winter season. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.770	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 18.839	$ 13.070	per kW
On-Peak Energy Charge:	$ 0.10029	$ 0.07603	per kWh
Off-Peak Energy Charge:	$ 0.05515	$ 0.05351	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.330	per day
Metering Charge	$ 0.258	per day
Meter Reading Charge	$ 0.087	per day
Billing Charge	$ 0.095	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$ 5.422	$ 3.198	per kW
Generation On-Peak kW Charge	$ 13.417	$ 9.872	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387	per kWh
Transmission Charge:	$ 0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.02143	$ 0.02364	per kWh
Generation On-Peak kWh Charge:	$ 0.06402	$ 0.03755	per kWh
Generation Off-Peak kWh Charge:	$ 0.01888	$ 0.01503	per kWh

FROZEN

The kW used to determine the demand charge above will be the highest amount of demand averaged in a one-hour On-Peak period for the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

FROZEN

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements - Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount - Legacy
Legacy E-4	Limited income medical discount - Legacy
GPS-1, GPS-2, GPS-3	Green Power

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar Customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the Customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new Customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

FROZEN

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

FROZEN

RATE SCHEDULE LEGACY ECT-2
RESIDENTIAL TIME-OF-USE SERVICE
WITH DEMAND CHARGE FOR
LEGACY ON-SITE DISTRIBUTED GENERATION

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program.

This rate schedule was frozen on September 1, 2017. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

FROZEN

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for this rate schedule is 12 p.m. to 7 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.770	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 18.743	$ 12.911	per kW
On-Peak Energy Charge:	$ 0.12147	$ 0.07815	per kWh
Off-Peak Energy Charge:	$ 0.05969	$ 0.05538	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.330	per day
Metering Charge	$ 0.258	per day
Meter Reading Charge	$ 0.087	per day
Billing Charge	$ 0.095	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$ 6.248	$ 3.332	per kW
Generation On-Peak kW Charge	$ 12.495	$ 9.579	per kW

FROZEN

Energy Charge Components

System Benefits Charge:	$ 0.00387	per kWh
Transmission Charge:	$ 0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.01943	$ 0.02208	per kWh
Generation On-Peak kWh Charge:	$ 0.08720	$ 0.04123	per kWh
Generation Off-Peak kWh Charge:	$ 0.02542	$ 0.01846	per kWh

The kW used to determine the demand charge above will be the highest amount of demand averaged in a one-hour On-Peak period for the month.

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

FROZEN

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements - Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount - Legacy
Legacy E-4	Limited income medical discount - Legacy
GPS-1, GPS-2, GPS-3	Green Power

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

FROZEN

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

FROZEN

RATE SCHEDULE LEGACY ET-1
RESIDENTIAL TIME-OF-USE SERVICE FOR LEGACY ON-SITE DISTRIBUTED GENERATION

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program that were on Rate Schedule ET-1 prior to January 1, 2010.

This rate schedule was frozen beginning on January 1, 2010. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

FROZEN

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for this rate schedule is 9 a.m. to 9 p.m. Monday through Friday. All other hours are Off-Peak hours. The rate also varies by summer and winter season. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.772	per day

	Summer	Winter	
On-Peak Energy Charge	$ 0.24749	$ 0.20050	per kWh
Off-Peak Energy Charge	$ 0.07894	$ 0.07533	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.331	per day
Metering Charge	$ 0.259	per day
Meter Reading Charge	$ 0.087	per day
Billing Charge	$ 0.095	per day

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Transmission Charge	$ 0.01097	per kWh
Delivery Charge	$ 0.03748	per kWh

	Summer	Winter	
Generation On-Peak Charge	$ 0.19517	$ 0.14818	per kWh
Generation Off-Peak Charge	$ 0.02662	$ 0.02301	per kWh

FROZEN

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements – Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount – Legacy
Legacy E-4	Limited income medical discount – Legacy
GPS-1, GPS-2, GPS-3	Green Power

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new Customer purchasing the home.

FROZEN

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

FROZEN

RATE SCHEDULE LEGACY ET-2
RESIDENTIAL TIME-OF-USE SERVICE FOR LEGACY ON-SITE DISTRIBUTED GENERATION
TIME ADVANTAGE 7PM-NOON

FROZEN

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program.

This rate schedule was frozen on September 1, 2017. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for this rate schedule is 12 p.m. to 7 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.772	per day

	Summer	Winter	
On-Peak Energy Charge:	$ 0.33776	$ 0.27392	per kWh
Off-Peak Energy Charge:	$ 0.08383	$ 0.08263	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.331	per day
Metering Charge	$ 0.259	per day
Meter Reading Charge	$ 0.087	per day
Billing Charge	$ 0.095	per day

Energy Charge Components

System Benefits Charge:	$ 0.00387	per kWh
Transmission Charge:	$ 0.01097	per kWh
Delivery Charge:	$ 0.03752	per kWh

	Summer	Winter	
Generation On-Peak Charge	$ 0.28540	$ 0.22156	per kWh
Generation Off-Peak Charge	$ 0.03147	$ 0.03027	per kWh

PROPOSED

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

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RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements – Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount – Legacy
Legacy E-4	Limited income medical discount – Legacy
GPS-1, GPS-2, GPS-3	Green Power

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new Customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

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SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

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RATE SCHEDULE R-1
RESIDENTIAL SERVICE
FIXED ENERGY CHARGE PLAN

AVAILABILITY

This rate schedule is available to full requirements residential Customers who do not have an on-site distributed generation system.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy or kilowatt-hours (kWh) is used during the month. This rate does not have time-of-use charges, seasonal charges, or a demand charge.

The Customer's applicable rate will be established by the annual average monthly energy consumption as determined by the Company. For Customers with an average monthly energy consumption of 600 kWh or less, the small tier (formerly Basic XS) charge applies. For Customers with an average monthly energy consumption of more than 600 kWh but less than 1,000 kWh, the medium tier (formerly Basic) charge applies. For Customers with an average monthly energy consumption of 1,000 kWh or more, the large tier (formerly Basic L) charge applies. For new residential Customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site.

Annual Review of Appropriate Usage Tier:
Annually in January, the Company will review the Customer's average monthly energy consumption during the previous 12 months. The Company uses Customer data from December of Year 1 through November of Year 2 to evaluate whether a Customer meets the usage criteria of the Customer's rate plan or should be reassigned. The Company will notify the Customer if the Customer's usage is below or exceeds the Customer's current energy usage tier, and that the Customer will be reassigned to a new tier consistent with the Customer's average monthly energy usage. The Company will provide each Customer whose average monthly usage during the year is approaching the next higher tier level at least two warnings about the consequences of exceeding the maximum threshold for the Customer's current tier.

The Company will provide a Customer a one-time waiver of this annual reassignment from the Customer's existing tier to the next higher tier based on the Customer's usage if the Customer contacts the Company.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Small - Tier 1 (Previously XS)

Basic Service Charge	$0.393	per day
Energy Charge	$0.13847	per kWh

Medium - Tier 2 (Previously Basic)

Basic Service Charge	$0.500	per day
Energy Charge	$0.15053	per kWh

Large - Tier 3 (Previously Basic L)

Basic Service Charge	$0.500	per day
Energy Charge	$0.16533	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Small Tier

Basic Service Charge Components

Customer Accounts Charge	$0.085	per day
Metering Charge	$0.128	per day
Meter Reading Charge	$0.085	per day
Billing Charge	$0.095	per day

Energy Charge Components

System Benefits Charge:	$0.00387	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03734	per kWh
Generation Charge	$0.08629	per kWh

Medium Tier

Basic Service Charge Components

Customer Accounts Charge	$0.085	per day
Metering Charge	$0.235	per day
Meter Reading Charge	$0.085	per day
Billing Charge	$0.095	per day

Energy Charge Components

System Benefits Charge	$0.00387	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03734	per kWh
Generation Charge	$0.09835	per kWh

Large Tier

Basic Service Charge Components

Customer Accounts Charge	$0.085	per day
Metering Charge	$0.235	per day
Meter Reading Charge	$0.085	per day
Billing Charge	$0.095	per day

Energy Charge Components

System Benefits Charge	$0.00387	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03734	per kWh
Generation Charge	$0.11315	per kWh

ADJUSTMENTS

The Customer's bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer's site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown below.

5. For purposes of A.R.S. §§ 33-1413.0l(B) and 33-2107(B)(3), the prevailing basic service single family residential rate charged by APS as the serving utility or provider is the middle tier of this tariff (Basic - 601-999 kWh).

RATE SCHEDULE R-2
RESIDENTIAL SERVICE
SAVER CHOICE PLUS

AVAILABILITY

This rate schedule is available to residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

This rate schedule was frozen as of December 1, 2021. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under this rate schedule, but no customers connecting any service after that date will be eligible to choose to be served under this rate schedule.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will not vary by season.

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TIME PERIODS

The On-Peak time period for this residential rate schedule is 3 p.m. to 8 p.m. Monday through Friday year-round. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.512	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 10.116	$ 10.116	per kW
On-Peak Energy Charge:	$ 0.15623	$ 0.13042	per kWh
Off-Peak Energy Charge:	$ 0.09197	$ 0.09184	per kWh

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Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.088	per day
Metering Charge	$ 0.240	per day
Meter Reading Charge	$ 0.086	per day
Billing Charge	$ 0.098	per day

Demand Charge Components

Delivery On-Peak kW Charge	$ 4.844	per kW
Generation On-Peak kW Charge	$ 5.272	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387	per kWh
Transmission Charge:	$ 0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.01339	$ 0.01326	per kWh
Generation On-Peak kWh Charge:	$ 0.12800	$ 0.10232	per kWh
Generation Off-Peak kWh Charge:	$ 0.06374	$ 0.06374	per kWh

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing month.

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to Partial Requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Direct Access Customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

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RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-RES	Critical Peak Pricing (Residential)
E-3	Limited income discount
E-4	Limited income medical discount
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

3. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

4. Electric service is supplied at a single point of delivery and measured through a single meter.

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

6. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor

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for purposes of the billing demand limitation described earlier using the following formula:

Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

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RATE SCHEDULE R-EV
RESIDENTIAL SERVICE
ELECTRIC VEHICLE TIME-OF-USE ENERGY CHARGES

AVAILABILITY

This rate schedule is available to Standard Offer electric service required for residential purposes in individual private dwellings and in individually metered apartments.

This rate is available to residential customers subject to ready access to an AMI network, the installation of required metering equipment and implementation of meter changes, and the completion of necessary enhancements to the Company's billing system.

This rate schedule is only applicable to customers who own a qualified electric vehicle as determined by the Company. Service under this schedule is also subject to an annual certification for proof of EV ownership. Neighborhood Electric Vehicles as described in A.R.S. §28-101(53) do not qualify for this rate schedule.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak, Off-Peak or Super Off-Peak).

TIME PERIODS

The On-Peak time period for this residential rate schedule is 4 p.m. to 7 p.m. Monday through Friday. The Super Off-Peak time period is 11 p.m. to 5 a.m every day, including holidays. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge		$ 0.500	per day
	Summer	Winter	
On-Peak Energy Charge	$ 0.49709	$ 0.46998	per kWh
Off-Peak Energy Charge	$ 0.13202	$ 0.13203	per kWh
Super Off-Peak Energy Charge	$ 0.03676	$ 0.03676	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.085	per day
Metering Charge	$ 0.235	per day
Meter Reading Charge	$ 0.085	per day
Billing Charge	$ 0.095	per day

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Transmission Charge	$ 0.01097	per kWh
Delivery On-Peak kWh Charge	$ 0.05080	per kWh
Delivery Off-Peak kWh Charge	$ 0.03734	per kWh
Delivery Super Off-Peak kWh Charge	$ 0.01326	per kWh

	Summer	Winter	
Generation On-Peak kWh Charge	$ 0.43145	$ 0.40434	per kWh
Generation Off-Peak kWh Charge	$ 0.07984	$ 0.07985	per kWh
Generation Super Off-Peak kWh Charge	$ 0.00866	$ 0.00866	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

RCP	Resource Comparison Proxy
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. This rate schedule requires the Customer to have a standard AMI meter in place.

2. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

3. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

4. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

5. Electric service is supplied at a single point of delivery and measured through a single meter.

6. This schedule is not applicable to breakdown, standby, supplemental or resale service.

7. Direct Access Customers are not eligible for this rate schedule.

AVAILABILITY

This rate schedule is available to residential Customers with the following:

1. Two or more qualifying primary on-site technologies purchased within 90 days of the Customer enrolling in the rate; or
2. One qualifying primary on-site technology purchased within 90 days of the Customer enrolling in the rate and two or more qualifying secondary on-site technologies.

This is a pilot rate schedule. This means this rate is associated with a specific program approved by the Arizona Corporation Commission, and is available only to those Customers eligible to participate in the program. The R-Tech pilot program will test the ability and desire of participating residential Customers to reduce On-Peak energy and demand usage through multiple behind-the-meter technologies.

Qualifying technologies for the R-Tech pilot program are as follows:

1. Primary technologies:
   a. A rooftop solar photovoltaic system. The size of the system cannot be smaller than 2 kW-dc. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the Customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the Customer's peak is 8 kW-ac, the maximum system size that could be installed would be 12 kW-dc).
   b. A chemical storage system. The size of the system cannot be smaller than 4 kWh. There is no maximum limitation for this technology.
   c. An electric vehicle. There are no limitations for this technology.

2. Secondary technologies:
   a. A device with a variable speed motor (such as a variable speed pool pump or a variable speed Heating, Ventilating, and Air Conditioning (HVAC) system).
   b. A grid-interactive water heating system.
   c. A smart thermostat.
   d. An automated load controller.

This rate schedule is initially limited to a maximum of 10,000 residential customers as outlined in Decision No. 76295.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the amount of demand (kW) averaged in a one-hour period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will also vary by season (summer or winter) and time of day (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for this residential rate schedule is 3 p.m. to 8 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Indigenous People's Day / Columbus Day – Second Monday in October
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge			$ 0.591	per day
		Summer	Winter	
On-Peak Demand Charge		$ 24.284	$ 17.089	per kW
Off-Peak Demand Charge	First 5 kW	$0.000	$0.000	per kW
	All remaining kW	$ 7.797	$ 7.797	
On-Peak Energy Charge		$ 0.06733	$ 0.05533	per kWh
Off-Peak Energy Charge		$ 0.05533	$ 0.05533	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.154	per day
Metering Charge	$ 0.257	per day
Meter Reading Charge	$ 0.085	per day
Billing Charge	$ 0.095	per day

Demand Charge Components

		Summer	Winter	
On-Peak Generation Charge		$ 16.489	$ 9.294	per kW
Off-Peak Generation Charge	First 5 kW	$0.000	$0.000	per kW
	All remaining kW	$ 1.200	$ 1.200	per kW
On-Peak Delivery Charge		$ 7.795	$ 7.795	per kW
Off-Peak Delivery Charge	First 5 kW	$0.000	$0.000	per kW
	All remaining kW	$ 6.597	$ 6.597	

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Transmission Charge	$ 0.01097	per kWh
Delivery Charge for all kWh	$ 0.00252	per kWh

	Summer	Winter	
Generation On-Peak kWh Charge	$ 0.04997	$ 0.03797	per kWh
Generation Off-Peak kWh Charge	$ 0.03797	$ 0.03797	per kWh

The kW used to determine the On-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the month.

The kW used to determine the Off-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour Off-Peak period during the weekday (Monday through Friday), excluding holidays that may fall on a weekday.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

RCP	Resource Comparison Proxy
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. This pilot rate schedule requires the Customer to have a standard AMI meter in place.

2. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

3. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

4. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

5. Electric service is supplied at a single point of delivery and measured through a single meter.

6. Direct Access Customers are not eligible for this rate schedule.

RATE SCHEDULE R-3
RESIDENTIAL SERVICE
TIME-OF-USE 4PM TO 7PM WEEKDAYS
WITH DEMAND CHARGE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system. This schedule replaces Time-of-Use 3 p.m. to 8 p.m. Weekdays with Demand Charge in accordance with Arizona Corporation Commission-approved changes in Decision No. 78317.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak, Off-Peak, or Super Off-Peak). The demand charge also varies by season.

TIME PERIODS

The On-Peak time period for residential rate schedules is 4 p.m. to 7 p.m. Monday through Friday. This rate also has a Super Off-Peak period, which is 10 a.m. to 3 p.m. Monday through Friday during the winter season, which is the November through April billing cycles. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve – December 24**
- Christmas Day - December 25*
- New Year's Eve – December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.500	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 21.113	$ 14.820	per kW
On-Peak Energy Charge:	$ 0.15250	$ 0.10615	per kWh
Off-Peak Energy Charge:	$ 0.06319	$ 0.06306	per kWh
Super Off-Peak Energy Charge:		$ 0.03676	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.085	per day
Metering Charge	$ 0.235	per day
Meter Reading Charge	$ 0.085	per day
Billing Charge	$ 0.095	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$ 4.844	$ 4.844	per kW
Generation On-Peak kW Charge	$ 16.269	$ 9.976	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387	per kWh
Transmission Charge:	$ 0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.01339	$ 0.01326	per kWh
Generation On-Peak kWh Charge:	$ 0.12427	$ 0.07805	per kWh
Generation Off-Peak kWh Charge:	$ 0.03496	$ 0.03496	per kWh
Generation Super Off-Peak kWh Charge:		$ 0.00866	per kWh

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing cycle.

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month up to a maximum of three instances per billing year, with only one of the three instances allowed during the summer season. This limitation is not available to Partial Requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP- RES	Critical Peak Pricing (Residential)
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

3. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

4. Electric service is supplied at a single point of delivery and measured through a single meter.

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

6. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE
TIME-OF-USE 4PM-7PM WEEKDAYS

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system. This schedule replaces Time-Of-Use 3 p.m. to 8 p.m. Weekdays in accordance with Arizona Corporation Commission-approved changes in Decision No. 78317.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak, Off-Peak, or Super Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for residential rate schedules is 4 p.m. to 7 p.m. Monday through Friday year-round. This rate also has a Super Off-Peak period, which is 10 a.m. to 3 p.m. Monday through Friday during the winter season, which is the billing cycles of November through April. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.500	per day

	Summer	Winter	
On-Peak Energy Charge	$ 0.36935	$ 0.34944	per kWh
Off-Peak Energy Charge	$ 0.13202	$ 0.13203	per kWh
Super Off-Peak Energy Charge		$ 0.03676	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.085	per day
Metering Charge	$ 0.235	per day
Meter Reading Charge	$ 0.085	per day
Billing Charge	$ 0.095	per day

Energy Charge Components

System Benefits Charge		$ 0.00387	per kWh
Transmission Charge		$ 0.01097	per kWh
	Summer	Winter	
Delivery Charge On-Peak	$ 0.03734	$ 0.03734	per kWh
Delivery Charge Off-Peak	$ 0.03734	$ 0.03734	per kWh
Delivery Charge Super Off-Peak		$ 0.01326	per kWh

Generation On-Peak Charge	$ 0.31717	$ 0.29726	per kWh
Generation Off-Peak Charge	$ 0.07984	$ 0.07985	per kWh
Generation Super Off-Peak Charge		$ 0.00866	per kWh

CHARGE FOR ON-SITE DISTRIBUTED GENERATION CUSTOMERS

The monthly bill for Customers on this rate schedule that have an on-site distributed generation system will also include a Grid Access Charge. This charge will apply to the nameplate kW-dc power rating of the Customer's distributed generation facility:

Grid Access Charge	$ -	per kW-dc of generation

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

3. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

4. Electric service is supplied at a single point of delivery and measured through a single meter.

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

RATE SCHEDULE E-30
GENERAL SERVICE
EXTRA SMALL UNMETERED

AVAILABILITY

This rate schedule is available to non-residential Customers who have consistent monthly energy and demand requirements.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge that varies based on the season. This plan is for Customers who have billing quantities that can be calculated without the use of metering equipment and service that can be supplied from a single point of delivery; such as sprinkler systems and cable television amplifiers.

TIME PERIODS

Summer season: May through October billing cycles
Winter season : November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.487	per day

	Summer	Winter	
Energy Charge	$ 0.16493	$ 0.14874	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts	$ 0.451	per day
Billing	$ 0.036	per day

Energy Charge Components

System Benefits	$ 0.00387	per kWh
Transmission	$ 0.00794	per kWh
Delivery	$ 0.05728	per kWh

	Summer	Winter	
Generation Charge	$ 0.09584	$ 0.07965	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SPECIAL PROVISIONS

1. Electric services being served on the Company's Rate Schedule E-30 prior to April 1, 2005 will continue to be served under this rate schedule; however, services eligible for this rate schedule after that date must meet the demand and energy requirements set forth below.

2. This rate schedule is only available to Customers whose monthly demand (kW) and energy (kWh) requirements remain constant. Monthly demand and energy requirements cannot exceed 1.44 kW (12 amperes) or 1,095 kWh at 120 volts, or 2.9 kW

(12 amperes) or 2,117 kWh at 240 volts. Determination of fixed monthly energy usage will be calculated based on the manufacturer's nameplate rating of the equipment and based on an average 730 hour month.

3. Prior written approval by an authorized Company representative is required before service is implemented under this rate schedule.

4. Prior written approval by an authorized Company representative is required for any change in loads. An unauthorized load change will automatically disqualify that Customer from service under this rate schedule.

5. The Company shall have the right to inspect the Customer's load facilities at any time to ensure compliance with all provisions of this rate schedule.

6. Service must be supplied at one site through one point of delivery as specified by the written approval.

7. This schedule is not applicable to breakdown, standby, supplemental, residential, or resale service.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedules E-34 or E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges (only one applies)		
For service through Self-Contained Meters	$ 3.657	per day
For service through Instrument-Rated Meters	$ 4.687	per day
For service at Primary Voltage	$ 8.195	per day
For service at Transmission Voltage	$ 46.362	per day

Demand Charges (only one set applies)			
Secondary	First 100 kW	$ 29.731	per kW
	All additional kW	$ 20.446	per kW
Primary	First 100 kW	$ 26.954	per kW
	All additional kW	$ 19.020	per kW
Transmission	First 100 kW	$ 20.469	per kW
	All additional kW	$ 13.452	per kW

	Summer	Winter	
Energy Charge	$ 0.06642	$ 0.04470	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 2.872	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.739	per day
Instrument-Rated Meters	$ 1.769	per day
Primary	$ 5.277	per day
Transmission	$ 43.444	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870	per kW
Generation		$ 6.533	per kW
Delivery - Secondary	First 100 kW	$ 20.328	per kW
	All additional kW	$ 11.043	per kW
Delivery - Primary	First 100 kW	$ 17.551	per kW
	All additional kW	$ 9.617	per kW
Delivery - Transmission	First 100 kW	$ 11.066	per kW
	All additional kW	$ 4.049	per kW

Energy Charge Components

System Benefits		$ 0.00387	per kWh
Delivery		$0.00000	per kWh
	Summer	Winter	
Generation	$ 0.06255	$ 0.04083	per kWh

For billing purposes, the kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32 TOU L that together have a combined load of at least 5 MW are eligible for a discount of $ (0.00293) per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements Service
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of greater than 100 kW and less than or equal to 400 kW.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges (only one applies)		
For service through Self-Contained Meters	$ 1.389	per day, or
For service through Instrument-Rated Meters	$ 2.418	per day, or
For service at Primary Voltage	$ 5.925	per day, or
For service at Transmission Voltage	$ 44.093	per day

Demand Charges (only one set applies)			
Secondary	First 100 kW	$ 14.007	per kW
	All additional kW	$ 7.762	per kW
Primary	First 100 kW	$ 12.927	per kW
	All additional kW	$ 6.874	per kW
Transmission	First 100 kW	$ 10.313	per kW
	All additional kW	$ 4.073	per kW

Energy Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.12666	$ 0.10727	per kWh
All additional kWh	$ 0.07811	$ 0.05891	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.740	per day, or
Instrument-Rated Meters	$ 1.769	per day, or
Primary	$ 5.276	per day, or
Transmission	$ 43.444	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870	per kW
Delivery - Secondary	First 100 kW	$ 11.137	per kW
	All additional kW	$ 4.892	per kW
Delivery - Primary	First 100 kW	$ 10.057	per kW
	All additional kW	$ 4.004	per kW
Delivery - Transmission	First 100 kW	$ 7.443	per kW
	All additional kW	$ 1.203	per kW

Energy Charge Components

System Benefit Charge	$ 0.00387	per kWh
Delivery Charge	$ 0.01549	per kWh

Generation Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.10730	$ 0.08791	per kWh, plus
All additional kWh	$ 0.05875	$ 0.03955	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 15-minute period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is

remedied, the Company may compute the customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with a monthly load of 21 kW up to and including 100 kW.

DESCRIPTION

This rate has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter). Demand charges also vary by voltage.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges		
For service through Self-Contained Meters	$ 1.389	per day
For service through Instrument-Rated Meters	$ 2.418	per day
For service at Primary Voltage	$ 5.925	per day

Demand Charges			
Secondary	First 100 kW	$ 13.177	per kW
	All additional kW	$ 7.408	per kW
Primary	First 100 kW	$ 12.286	per kW
	All additional kW	$ 6.517	per kW

Energy Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.12963	$ 0.11045	per kWh
All additional kWh	$ 0.08121	$ 0.06204	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.740	per day, or
Instrument-Rated Meters	$ 1.769	per day, or
Primary	$ 5.276	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission Charge		$ 2.870	per kW
Delivery - Secondary	First 100 kW	$ 10.307	per kW
	All additional kW	$ 4.538	per kW
Delivery - Primary	First 100 kW	$ 9.416	per kW
	All additional kW	$ 3.647	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Delivery Charge	$ 0.01683	per kWh

Generation Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.10893	$ 0.08975	per kWh
All additional kWh	$ 0.06051	$ 0.04134	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 15-minute period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56 R	Partial Requirements – Renewable
GPS-1, GPS-2. GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

AVAILABILITY

This rate schedule is available to non-residential Customers, and to Customers with secondary services at residential sites that are separately metered such as wells or detached garages.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter). This rate is a General Service rate for Customers with an average summer monthly maximum demand of 20 kW or less per month based on the Customer's average demand (kW) supplied during the 1-hour period of maximum use during the month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges		
For service through Self-Contained Meters	$ 1.389	per day
For service through Instrument-Rated Meters	$ 2.418	per day
For service at Primary Voltage	$ 5.925	per day

Energy Charges:			
	Summer	Winter	
Secondary Service – First 5,000 kWh	$ 0.16199	$ 0.14227	per kWh
Secondary Service – All Additional kWh	$ 0.08930	$ 0.06916	per kWh
Primary Service – First 5,000 kWh	$ 0.15777	$ 0.13799	per kWh
Primary Service – All Additional kWh	$ 0.08468	$ 0.06493	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts Charges:	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Meter* (only one applies)		
Self-Contained Meters	$ 0.740	per day
Instrument-Rated Meters	$ 1.769	per day
Primary	$ 5.276	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Energy Charges

System Benefits Charge	$ 0.00387	per kWh
Transmission Charge	$ 0.00794	per kWh

Delivery (only one set applies)				
		Summer	Winter	
Secondary	First 5,000 kWh	$ 0.05375	$ 0.05369	per kWh
	All additional kWh	$ 0.01728	$ 0.01679	per kWh
Primary	First 5,000 kWh	$ 0.04953	$ 0.04941	per kWh
	All additional kWh	$ 0.01266	$ 0.01256	per kWh

Generation Charges			
	Summer	Winter	
First 5,000 kWh	$ 0.09643	$ 0.07677	per kWh
All additional kWh	$ 0.06021	$ 0.04056	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
SD-1	School Discount
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

RATE SCHEDULE E-32 XS D
EXTRA SMALL GENERAL SERVICE
WITH DEMAND (0 kW - 20 kW)

AVAILABILITY

This rate schedule is available to non-residential Customers and to Customers with secondary services at residential sites that are separately metered such as wells or detached garages.

DESCRIPTION

This rate is a General Service rate for Customers with an average summer monthly maximum demand of 20 kW or less per month. This rate has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 1-hour period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges:		
For service through Self-Contained Meters	$ 1.389	per day
For service through Instrument-Rated Meters	$ 2.418	per day
For service at Primary Voltage	$ 5.925	per day

	Summer	Winter	
Secondary Service Demand Charge	$ 8.393	$ 8.393	per kW
Primary Service Demand Charge	$ 5.231	$ 5.231	per kW
Secondary Service Energy Charge	$ 0.12676	$ 0.10350	per kWh
Primary Service Energy Charge	$ 0.11949	$ 0.09646	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charges:	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.740	per day
Instrument-Rated Meters	$ 1.769	per day
Primary	$ 5.276	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Delivery Secondary	$ 8.393	per kW
Delivery Primary	$ 5.231	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Transmission Charge	$ 0.00794	per kWh

Delivery Charges (only one applies)			
	Summer	Winter	
For Secondary Service	$ 0.01701	$ 0.01678	per kWh
For Primary Service	$ 0.00974	$ 0.00974	per kWh

	Summer	Winter	
Generation Charge	$ 0.09794	$ 0.07491	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 1-hour period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
SD-1	Schools Discount
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedule E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule Time-of-Use E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 3.657	per day
For service through Instrument-Rated Meters	$ 4.687	per day
For service at Primary Voltage	$ 8.195	per day
For service at Transmission Voltage	$ 46.362	per day

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	$ 20.338	per kW
	All additional On-Peak kW	$ 13.505	per kW
	First 100 Off-Peak kW	$ 7.636	per kW
	All additional Off-Peak kW	$ 4.017	per kW
Primary	First 100 On-Peak kW	$ 19.653	per kW
	All additional On-Peak kW	$ 13.401	per kW
	First 100 Off-Peak kW	$ 6.779	per kW
	All additional Off-Peak kW	$ 3.899	per kW
Transmission	First 100 On-Peak kW	$ 18.433	per kW
	All additional On-Peak kW	$ 11.927	per kW
	First 100 Off-Peak kW	$ 5.811	per kW
	All additional Off-Peak kW	$ 3.737	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$ 0.08411	$ 0.06669	per kWh
Off-Peak	$ 0.06879	$ 0.05136	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 2.872	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day

Metering* (only one applies)		
Self-Contained Meters	$ 0.739	per day
Instrument-Rated Meters	$ 1.769	per day
Primary	$ 5.277	per day
Transmission	$ 43.444	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870	per kW
Generation On-Peak		$ 7.110	per kW
Generation Off-Peak		$ 2.706	per kW
Delivery - Secondary	First 100 On-Peak kW	$ 10.358	per kW
	All additional On-Peak kW	$ 3.525	per kW
	First 100 Off-Peak kW	$ 4.930	per kW
	All additional Off-Peak kW	$ 1.311	per kW
Delivery - Primary	First 100 On-Peak kW	$ 9.673	per kW
	All additional On-Peak kW	$ 3.421	per kW
	First 100 Off-Peak kW	$ 4.073	per kW
	All additional Off-Peak kW	$ 1.193	per kW
Delivery - Transmission	First 100 On-Peak kW	$ 8.453	per kW
	All additional On-Peak kW	$ 1.947	per kW
	First 100 Off-Peak kW	$ 3.105	per kW
	All additional Off-Peak kW	$ 1.031	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387	per kWh
Delivery Charge	$ 0.01444	Per kWh

	Summer	Winter	
Generation On-Peak	$ 0.06580	$ 0.04838	per kWh
Generation Off-Peak	$ 0.05048	$ 0.03305	per kWh

For billing purposes, the On-Peak kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during the On-Peak period during the billing period, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest On-Peak kW measured during the six summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

Off-peak kW will be based on the average kW supplied during the 15-minute period of maximum use during the Off-peak hours of the billing period, as determined from readings of the Company's meter.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of $ (0.00293) per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 101 kW up to 400 kW.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 1.389	per day
For service through Instrument-Rated Meters	$ 2.418	per day
For service at Primary Voltage	$ 5.925	per day
For service at Transmission Voltage	$ 44.093	per day

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	$ 21.244	per kW
	All additional On-Peak kW	$ 13.495	per kW
	First 100 Off-Peak kW	$ 8.089	per kW
	All additional Off-Peak kW	$ 3.983	per kW
Primary	First 100 On-Peak kW	$ 20.471	per kW
	All additional On-Peak kW	$ 13.378	per kW
	First 100 Off-Peak kW	$ 7.119	per kW
	All additional Off-Peak kW	$ 3.849	per kW
Transmission	First 100 On-Peak kW	$ 19.085	per kW
	All additional On-Peak kW	$ 12.901	per kW
	First 100 Off-Peak kW	$ 6.021	per kW
	All additional Off-Peak kW	$ 3.670	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$ 0.08623	$ 0.06968	per kWh
Off-Peak	$ 0.07170	$ 0.05513	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day

Metering* (only one applies)		
Self Contained Meters	$ 0.740	per day
Instrument-Rated Meters	$ 1.769	per day
Primary	$ 5.276	per day
Transmission	$ 43.444	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870	per kW
Generation On-Peak		$ 5.863	per kW
Generation Off-Peak		$ 2.231	per kW
Delivery - Secondary	First 100 On-Peak kW	$ 12.511	per kW
	All additional On-Peak kW	$ 4.762	per kW
	First 100 Off-Peak kW	$ 5.858	per kW
	All additional Off-Peak kW	$ 1.752	per kW
Delivery - Primary	First 100 On-Peak kW	$ 11.738	per kW
	All additional On-Peak kW	$ 4.645	per kW
	First 100 Off-Peak kW	$ 4.888	per kW
	All additional Off-Peak kW	$ 1.618	per kW
Delivery - Transmission	First 100 On-Peak kW	$ 10.352	per kW
	All additional On-Peak kW	$ 4.168	per kW
	First 100 Off-Peak kW	$ 3.790	per kW
	All additional Off-Peak kW	$ 1.439	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Delivery Charge	$ 0.00372	per kWh

	Summer	Winter	
Generation On-Peak	$ 0.07864	$ 0.06209	per kWh
Generation Off-Peak	$ 0.06411	$ 0.04754	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 15-minute period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with a monthly load of 21 kW up to 100 kW.

DESCRIPTION

This rate has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by both season (summer or winter) and the time of day that the energy is used (On-Peak or Off-Peak).

The Company will place the Customer on the applicable Rate Schedule E-32 TOU XS, E-32 TOU S, E-32 TOU M, or E-32 TOU L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer months:	May through October
Winter months:	November through April

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 1.389	per day
For service through Instrument-Rated Meters	$ 2.418	per day
For service at Primary Voltage	$ 5.925	per day

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	$ 23.541	per kW
	All additional On-Peak kW	$ 11.743	per kW
	First 100 Off-Peak kW	$ 9.522	per kW
	All additional Off-Peak kW	$ 3.275	per kW
Primary	First 100 On-Peak kW	$ 22.363	per kW
	All additional On-Peak kW	$ 11.569	per kW
	First 100 Off-Peak kW	$ 8.045	per kW
	All additional Off-Peak kW	$ 3.073	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$ 0.08679	$ 0.06799	per kWh
Off-Peak	$ 0.06601	$ 0.05016	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.740	per day
Instrument-Rated Meters	$ 1.769	per day
Primary	$ 5.276	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870	per kW
Generation – Capacity On-Peak		$ 5.185	per kW
Generation – Capacity Off-Peak		$ 1.972	per kW
Delivery - Secondary	First 100 On-Peak kW	$ 15.486	per kW
	All additional On-Peak kW	$ 3.688	per kW
	First 100 Off-Peak kW	$ 7.550	per kW
	All additional Off-Peak kW	$ 1.303	per kW
Delivery - Primary	First 100 On-Peak kW	$ 14.308	per kW
	All additional On-Peak kW	$ 3.514	per kW
	First 100 Off-Peak kW	$ 6.073	per kW
	All additional Off-Peak kW	$ 1.101	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh

	Summer	Winter	
Generation On-Peak	$ 0.08292	$ 0.06412	per kWh
Generation Off-Peak	$ 0.06214	$ 0.04629	per kWh

The kW used to determine the demand charge as shown will be the Customer's highest 15-minute On-Peak energy used during the billing month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available to non-residential Customers and Customers with secondary services at residential sites that are separately metered such as wells or detached garages. The Customer must have a monthly load of 20 kW or less to be served on this rate schedule.

DESCRIPTION

This rate has three-parts: a basic service charge; a demand charge for the average demand (kW) supplied during the one-hour period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The demand charge may vary by season and the energy charge will vary by both season (summer or winter) and the time of day that the energy is used (On-Peak or Off-Peak).

The Company will place the Customer on the applicable Rate Schedule E-32 TOU XS, E-32 TOU S, E-32 TOU M, or E-32 TOU L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges		
For service through Self-Contained Meters	$ 1.389	per day
For service through Instrument-Rated Meters	$ 2.418	per day
For service at Primary Voltage	$ 5.925	per day

Demand Charges (only one set applies)			
Secondary	On-Peak kW	$ 5.497	per kW
	Off-Peak kW	$ 3.143	per kW
Primary	On-Peak kW	$ 4.775	per kW
	Off-Peak kW	$ 1.890	per kW

Energy Charges (only one set applies)				
		Summer	Winter	
Secondary	On-Peak	$ 0.17871	$ 0.14248	per kWh
	Off-Peak	$ 0.13662	$ 0.10885	per kWh
Primary	On-Peak	$ 0.17628	$ 0.14005	per kWh
	Off-Peak	$ 0.12909	$ 0.10132	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Meter* (only one applies)		
Self-Contained Meters	$ 0.740	per day
Instrument-Rated Meters	$ 1.769	per day
Primary Meters	$ 5.276	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Delivery Components (only one set applies)			
Secondary	On-Peak kW	$ 1.934	per kW
	Off-Peak kW	$ 1.313	per kW
Primary	On-Peak kW	$ 1.212	per kW
	Off-Peak kW	$ 0.060	per kW

Generation	On-Peak kW	$ 3.563	per kW
	Off-Peak kW	$ 1.830	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387	per kWh
Transmission Charge	$ 0.00794	per kWh

Delivery Components (only one set applies)			
Secondary	On-Peak	$ 0.06910	per kWh
	Off-Peak	$ 0.04390	per kWh
Primary	On-Peak	$ 0.06667	per kWh
	Off-Peak	$ 0.03637	per kWh

	Summer	Winter	
Generation On-Peak	$ 0.09780	$ 0.06157	per kWh
Generation Off-Peak	$ 0.08091	$ 0.05314	per kWh

The kW used to determine the demand charge as shown above will be the Customer's highest one-hour On-Peak and Off-Peak energy used during the billing month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
SD-1	Schools Discount
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to Customers whose monthly maximum demand registers 3,000 kW or more for 3 consecutive months, over the prior 12 months.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period of maximum use during the month, and an energy charge for the total energy (kWh) used for the entire month.

CHARGES

The monthly bill will be calculated with the following charges plus adjustments. A Customer's charge will depend on the voltage of their service connection.

Bundled Charges

Customers Served at Secondary Voltage		
Basic Service Charge for Self-Contained Meters	$ 5.156	per day
Basic Service Charge for Instrument-Rated Meters	$ 6.159	per day
Demand Charge	$ 25.216	per kW
Energy Charge	$ 0.04714	per kWh

Customers Served at Primary Voltage		
Basic Service Charge	$ 9.573	per day
Demand Charge	$ 23.682	per kW
Energy Charge	$ 0.04714	per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$ 46.732	per day
Demand Charge	$ 16.114	per kW
Energy Charge	$ 0.04714	per kWh

Eligible Military Base Customers		
Basic Service Charge	$ 9.573	per day
Demand Charge	$ 17.219	per kW
Energy Charge	$ 0.04714	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 4.388	per day
Meter Reading	$ 0.012	per day
Billing	$ 0.036	per day
Meter (only one applies)		
Self-Contained Meter	$ 0.720	per day
Instrument-Rated Meter	$ 1.723	per day
Primary Meter	$ 5.137	per day
Transmission Meter	$ 42.296	per day
Demand Charge Components		
Generation	$ 12.429	per kW
Transmission	$ 3.236	per kW
Delivery (only one applies)		
Secondary Service	$ 9.551	per kW
Primary Service	$ 8.017	per kW
Transmission Service	$ 0.449	per kW
Eligible Military Base	$ 1.554	per kW
Energy Charge Components		
Generation	$ 0.04327	per kWh
System Benefits	$ 0.00387	per kWh

The kW for billing will be the greater of:

a. The average kW supplied during the 15-minute period of maximum use during the monthly billing period; or

b. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

c. The minimum kW specified in a service agreement. A time period other than 15 minutes can be specified in a service agreement.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
E-56	Partial requirements – General
E-56R	Partial requirements – Renewable
EPR-2	Partial requirements – Net billing
EPR-6	Partial Requirements – Net Metering
GPS-1, GPS-2, GPS-3	Green Power
IRR	Interruptible program
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. Service under this schedule is generally provided at secondary voltage. When the Customer owns the distribution transformer(s) service is provided at primary voltage.

2. The type of service provided under this schedule will be three-phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

3. Daily metering charges apply to typical installations. Customers requiring specialized equipment may incur additional metering charges that reflect the additional cost.

4. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the partial requirement rate riders.

5. Some Customers will have a service agreement that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges and other service details. This typically includes Customers taking service at primary or transmission level voltage and those on various special rates and programs.

6. Eligible military base refers to a military base receiving service at a primary voltage and served from a dedicated distribution feeder.

7. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

8. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

9. This schedule is not applicable to breakdown, standby, supplemental, residential, or resale service.

10. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to Customers whose monthly maximum demand registers 3,000 kW or more for 3 consecutive months, over the prior 12 months.

DESCRIPTION

This rate has three parts: a basic service charge, a demand (kW) charge, and an energy charge for the energy (kWh) used for the entire month. Both the demand charge and the energy charge will vary by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

On-Peak hours	11:00 a.m. - 9:00 p.m. Monday through Friday
Off-Peak hours	All remaining hours

CHARGES

The monthly bill will be calculated at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Service

Customers Served at Secondary Voltage		
Basic Service Charge for Self-Contained Meters	$ 5.156	per day
Basic Service Charge for Instrument-Rated Meters	$ 6.159	per day
Demand Charge On-Peak	$ 21.544	per kW
Demand Charge Off-Peak	$ 3.401	per kW
Energy Charge On-Peak	$ 0.05189	per kWh
Energy Charge Off-Peak	$ 0.04125	per kWh

Customers Served at Primary Voltage		
Basic Service Charge	$ 9.573	per day
Demand Charge On-Peak	$ 20.073	per kW
Demand Charge Off-Peak	$ 3.254	per kW
Energy Charge On-Peak	$ 0.05189	per kWh
Energy Charge Off-Peak	$ 0.04125	Per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$ 46.732	per day
Demand Charge On-Peak	$ 12.470	per kW
Demand Charge Off-Peak	$ 2.492	per kW
Energy Charge On-Peak	$ 0.05189	per kWh
Energy Charge Off-Peak	$ 0.04125	Per kWh

Eligible Military Base Customers		
Basic Service Charge	$ 9.573	per day
Demand Charge On-Peak	$ 14.513	per kW
Demand Charge Off-Peak	$ 2.696	per kW
Energy Charge On-Peak	$ 0.05189	per kWh
Energy Charge Off-Peak	$ 0.04125	Per kWh

Unbundled Standard Offer Service

Bundled Charges consists of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 4.388	per day
Meter Reading	$ 0.012	per day
Billing	$ 0.036	per day
Meter (only one applies)		
Self-Contained Meter	$ 0.720	per day
Instrument-Rated Meters	$ 1.723	per day
Primary Meter	$ 5.137	per day
Transmission Meter	$ 42.296	per day
Demand Charge Components		
Transmission Charge On-Peak	$ 3.236	per kW
Generation Charge On-Peak	$ 8.558	per kW
Generation Charge Off-Peak	$ 2.426	per kW

Delivery (only one set of charges applies)			
Secondary	On-Peak	$ 9.750	per kW
	Off-Peak	$ 0.975	per kW
Primary	On-Peak	$ 8.279	per kW
	Off-Peak	$ 0.828	per kW
Transmission	On-Peak	$ 0.676	per kW
	Off-Peak	$ 0.066	per kW
Eligible Military Bases	On-Peak	$ 2.719	per kW
	Off-Peak	$ 0.270	per kW
Energy Charge Components			
Generation On-Peak		$ 0.04802	per kWh
Generation Off-Peak		$ 0.03738	per kWh
System Benefits		$ 0.00387	per kWh

MINIMUM BILL

The bill will not be less than the Basic Service Charge plus the Demand Charge for the minimum kW specified in the Customer's service agreement or contract.

For billing kW purposes:

a. The On-Peak is based on the greater of the following:

   i. The average kW supplied during the 15-minute period of maximum use during the billing period; or

   ii. 80% of the highest On-Peak kW measured during May through October of the twelve months ending with the current month.

b. Off-Peak is based on the average kW supplied during the 15-minute period of maximum use during Off-Peak hours.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
E-56R	Partial requirements – Renewable
EPR-2	Partial requirements – Net billing
EPR-6	Partial Requirements – Net Metering
GPS-1, GPS-2, GPS-3	Green Power
IRR	Interruptible program
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.
2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. Service under this schedule is generally provided at secondary voltage. When the Customer owns the distribution transformer(s) service is provided at primary voltage.

2. The type of service provided under this schedule will be three-phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

3. Daily metering charges apply to typical installations. Customers requiring specialized Equipment may incur additional metering charges that reflect the additional cost.

4. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the partial requirement rate riders.

5. Some Customers will have a service agreement or contract that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges, and other service details.

6. Eligible military base refers to a military base receiving service at a primary voltage and served from a dedicated distribution feeder.

7. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

8. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

9. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

10. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

AVAILABILITY

This rate schedule is available to Customers: (i) whose monthly maximum demand is 5,000 kW or more; (ii) with a load factor of 92% or more for a minimum of nine months of the prior 12 month period; and (iii) where the Customer also seeks the Economic Development and Sustainability features described below, the Customer must also meet a monthly demand of 15,000 kW, and the 50% Carbon Free Activity requirement set out in this rate schedule.

Customers will be required to execute an Electric Supply Agreement (ESA) that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges, and other service details, including maintenance.

Customers with monthly demands of 15,000 kW or greater may choose to be served with transmission level service by providing the Company with a contribution in aid of construction (CIAC) in lieu of purchasing transmission level facilities. For new Customers, this will be addressed in their Line Extension Agreement pursuant to Service Schedule 3. The Customer will be required to execute a maintenance contract and share in the cost of replacement facilities. Under this option, the Company may also finance the CIAC at the Company's weighted average cost of capital established in its most recent rate case. This financing period will not exceed 10 years.

50% CARBON FREE ACTIVITY REQUIREMENT AND SUSTAINABILITY FEATURES

In addition to having a monthly demand of at least 15,000 kW and having a load factor of 92%, a Customer within the Company's service territory seeking to manage sustainability goals, must demonstrate that it is carbon free for at least 50% of its energy consumption on an annual basis within APS territory. The 50% requirement can be met through Renewable Energy Credits, Carbon Credits, carbon offsets or demonstrated improvement in Carbon Free Activity, and will be specified in the Customer's ESA with the Company. Carbon Free Activities are load shifting, new load added during carbon free curtailment periods, advancements in electrification, energy storage or electric vehicle charging during carbon free curtailment periods.

The Economic Development and Sustainability features below will be limited to an additional 50 MW of load annually per Customer and will not exceed 500 MW in total Customer load unless there is sufficient long-term market liquidity to do so, as determined by APS in its sole discretion. APS will evaluate long-term market liquidity with Customer's receiving service under this rate schedule at least once per year.

DESCRIPTION

This rate has three parts: a basic service charge, a demand (kW) charge consisting of the average kW supplied during the 15-minute period of maximum use during the billing period, and an energy (kWh) charge for the energy used for the entire month.

Monthly load factor will be established using the formula:

Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

CHARGES

The monthly bill will be calculated at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Service

Customers Served at Secondary Voltage		
Basic Service Charge	$ 6.159	per day
Demand Charge	$ 20.643	per kW
Energy Charge	$ 0.04416	per kWh

Customers Served at Primary Voltage		
Basic Service Charge	$ 9.573	per day
Demand Charge	$ 19.056	per kW
Energy Charge	$ 0.04416	per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$ 46.732	per day
Demand Charge	$ 14.688	per kW
Energy Charge	$ 0.04416	per kWh

Unbundled Standard Offer Service

Bundled Charges consists of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 4.388	per day
Meter Reading	$ 0.012	per day
Billing	$ 0.036	per day
Meter (only one applies)		
Instrument-Rated Meter	$ 1.723	per day
Primary Meter	$ 5.137	per day
Transmission Meter	$ 42.296	per day
Demand Charge Components		
Transmission Charge	$ 3.236	per kW
Generation - Capacity	$ 10.971	per kW
Delivery (only one applies)		
Secondary Service	$ 6.436	per kW
Primary Service	$ 4.849	per kW
Transmission Service	$ 0.481	per kW
Energy Charge Components		
Generation - Fuel	$ 0.04029	per kWh
System Benefits	$ 0.00387	per kWh

The kW for billing will be the greater of:

a. The average kW supplied during the 15-minute period of maximum use during the monthly billing period; or

b. The minimum kW specified in a service agreement.

MINIMUM BILL

The bill will not be less than the minimum amount specified in the Customer's service agreement or contract.

ECONOMIC DEVELOPMENT AND SUSTAINABILITY

Qualifying Customers will be eligible for one or more of the following additional features:

1. The "Generation – Fuel" and "Power Supply Adjustment Charges" may be replaced with a loss adjusted market proxy index price using the Intercontinental Exchange (ICE) day-ahead on and off-peak prices for the Palo Verde hub, or successor index, plus a non-bypassable fuel cost and administrative fee of $0.00342 per kWh. In any billing cycle, the combined average of the on and off-peak market proxy index price shall not be less than zero.

2. An Economic Development discount, for new load only, not to exceed 35% on the bundled or unbundled "Generation – Capacity" charge referenced above for a period not to exceed six years. Such terms and date for implementation of the discount will be specified in the Customer's ESA with the Company, based on an evaluation of criteria as described in the Company's Service Schedule 9.

3. A "Generation – Capacity" Credit denominated on a dollar per kW basis for providing APS the ability to remove the load from APS's system through a microgrid, battery or otherwise that provides APS sufficient flexible control of the Customer's load on APS's system. The Credit will be based on a resource planning analysis and will be specified in the Customer's ESA with the Company. The sum of the Economic Development discount and Generation Capacity Credit shall not exceed the "Generation – Capacity" charge specified in this Rate Schedule XHLF. To the extent a Customer is otherwise receiving a capacity credit from the Company, the capacity generating this credit is not also eligible for the "Generation – Capacity" credit described herein.

4. If a Customer fails to meet a 92% load factor in a particular billing cycle solely due to load growth within that billing cycle, the billing cycle will not count against the Customer's compliance with the load factor provisions in this Rate Schedule XHLF.

5. If a Customer meets its carbon free demonstration through renewable resources under its ownership or control, the Customer may not schedule energy into the Company's service territory to self supply energy.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1, unless the Customer has demonstrated its 50% carbon free commitment described above. Customer loads for Customers who have demonstrated their carbon free commitment will not be included in

APS's load for purposes of determining achievement of the Commission's Renewable Energy Standard. This provision will be reviewed if the Commission's Renewable Energy Standards are modified or replaced.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1, unless the Customer has selected the loss adjusted market proxy index price mechanism.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1. This will be set out in the ESA.

5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

7. Any applicable taxes and governmental fees that are assessed on APS's revenue, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

GPS-1, GPS-2, GPS-3	Green Power

Qualifying Customers taking service under the Economic Development and Sustainability provisions of this rate schedule are not eligible for rate riders GPS-1, GPS-2, or GPS-3.

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. The type of service provided under this schedule will be three-phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

2. Daily metering charges apply to typical installations. Customers requiring specialized Equipment may incur additional metering charges that reflect the additional cost.

3. Customers that self-provide some of their electrical requirements from primary on-site generation will be billed according to one of the partial requirement rate riders.

4. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

5. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

6. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this Schedule, but are not eligible for the Economic Development and Sustainability features. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by the Company and billed to the Customer at the charges shown above.

7. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

RATE SCHEDULE E-20
CLASSIFIED TIME-OF-USE SERVICE
FOR RELIGIOUS HOUSES OF WORSHIP

AVAILABILITY

This rate schedule is applicable to non-taxable religious houses of worship.

The Company may request a copy of the Internal Revenue Service letter in which the Customer's non-taxable status as a religious organization is determined. Customers also agree to provide the Company a copy of any Internal Revenue Service letter which changes or supersedes that tax status determination.

DESCRIPTION

This rate schedule is specifically for places of worship. It is only available to the actual sanctuary or principal place of worship, and does not apply to separate or combined facilities such as kitchens or meeting rooms.

This rate has three parts: a basic service charge, a demand charge, and an energy charge. The energy charge will vary by season (summer or winter) and both the demand and energy charge will vary by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

On-Peak hours:	11:00 a.m. to 9:00 p.m. Monday through Friday.
Off-Peak hours:	All remaining hours.
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 2.418	per day

Demand and Energy Charges			
	Summer	Winter	
On-Peak Demand Charge	$ 4.008	$ 4.008	per kW
Off-Peak Excess Demand Charge	$ 2.935	$ 2.935	per kW
On-Peak Energy Charge:	$ 0.18924	$ 0.16689	per kWh
Off-Peak Energy Charge:	$ 0.09244	$ 0.08304	per kWh

In the event Off-Peak kW usage is greater than twice the highest On-Peak kW usage in a month, the difference between the Off-Peak kW usage and twice the On-Peak kW usage will be billed at the Off-Peak Excess Demand Charge. Total On-Peak kW usage for the month will also be billed as shown above.

For billing purposes, the kW used in this rate schedule is based on the average kW used during the 15-minute period of maximum use during the On-Peak period and the Off-Peak period during the month.

Unbundled Standard Offer Service

Bundled Charges consist of the Components shown below. These are not additional charges.

Basic Service Charges		
Customer Accounts	$ 0.603	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Metering	$ 1.769	per day

Demand Charges			
Transmission Charge On-Peak		$ 2.870	per kW
Delivery Charge On-Peak		$ 1.138	per kW
Delivery Charge Excess Off-Peak		$ 2.935	per kW
Energy Charges			
	Summer	Winter	
Generation On-Peak	$ 0.13888	$ 0.11653	per kWh
Generation Off-Peak	$ 0.04208	$ 0.03268	per kWh
Delivery	$ 0.04649	$ 0.04649	per kWh
System Benefits	$ 0.00387	$ 0.00387	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

5. This rate schedule is not available to service for which Rate Schedules E-34 or E-35 is applicable.

6. Direct Access Customers are not eligible for this rate schedule.

AVAILABILITY

This rate schedule is for a pilot rate available only to non-residential Customers that:

a. have average summer monthly loads of 401 kW and greater;
b. do not qualify for Rate Schedules E-34 or E-35;
c. are not taking service under rate rider AG-X or through Direct Access; and
d. operate a chemical, mechanical, or thermal energy storage system located on their premises.

This rate schedule will be capped at a peak demand total of 35,000 kW of installed systems and active interconnection applications, on a first-come first-served basis. Availability of this rate is subject to the availability of required metering equipment and completion of necessary enhancements to the Company's billing system.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The demand and energy charges vary by season (summer or non-summer) and time of day (On-Peak, Remaining, and Off-Peak).

If Customer no longer meets the requirements of this rate schedule, the Company will place the Customer on the applicable Time-of-Use Rate Schedule (E-32TOU XS, E-32 TOU S, E-32 TOU M, E-32 TOU L) based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer Hours	
On-Peak hours:	4:00 pm – 7:00 pm weekdays
Remaining hours:	11:00 am – 4:00 pm and 7:00 pm - 11:00 pm weekdays; 11:00 am – 11:00 pm weekends
Off-Peak hours:	All remaining hours
Non-Summer Hours	
On-Peak hours:	4:00 pm – 7:00 pm weekdays
Remaining hours:	6:00 am – 10:00 am, 3:00 pm - 4:00 pm and 7:00 pm - 11:00 pm weekdays; 6:00 am – 10:00 am and 3:00 pm – 11:00 pm weekends
Off-Peak hours:	All remaining hours

Summer season: Calendar months June 1st through September 30th
Non-Summer season: Calendar months October 1st through May 31st

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 3.657	per day
For service through Instrument-Rated Meters	$ 4.687	per day
For service at Primary Voltage	$ 8.195	per day
For service at Transmission Voltage	$ 46.362	per day

Demand Charges (only one set applies)			
Secondary	Summer On-Peak kW	$ 15.251	per kW
	Summer Remaining-Peak kW	$ 4.762	per kW
	Non-Summer On-Peak kW	$ 13.688	per kW
	Non-Summer Remaining-Peak kW	$ 4.161	per kW
Primary	Summer On-Peak kW	$ 14.208	per kW
	Summer Remaining-Peak kW	$ 4.361	per kW
	Non-Summer On-Peak kW	$ 12.646	per kW
	Non-Summer Remaining-Peak kW	$ 3.760	per kW
Transmission	Summer On-Peak kW	$ 12.126	per kW
	Summer Remaining-Peak kW	$ 3.560	per kW
	Non-Summer On-Peak kW	$ 10.563	per kW
	Non-Summer Remaining-Peak kW	$ 2.959	per kW

Energy Charges			
	Summer	Non-Summer	
On-Peak	$ 0.08255	$ 0.06539	per kWh
Remaining	$ 0.07818	$ 0.06246	per kWh
Off-Peak	$ 0.07090	$ 0.05475	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 2.872	per day
Meter Reading	$ 0.011	per day
Billing	$ 0.035	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.739	per day
Instrument-Rated Meters	$ 1.769	per day
Primary	$ 5.277	per day
Transmission	$ 43.444	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission On-Peak		$ 2.870	per kW
Generation On-Peak		$ 5.367	per kW
Generation Remaining-Peak		$ 2.064	per kW
Delivery - Secondary	Summer On-Peak kW	$ 7.014	per kW
	Summer Remaining-Peak kW	$ 2.698	per kW
	Non-Summer On-Peak kW	$ 5.451	per kW
	Non-Summer Remaining-Peak kW	$ 2.097	per kW

Delivery - Primary	Summer On-Peak kW	$ 5.971	per kW
	Summer Remaining -Peak kW	$ 2.297	per kW
	Non-Summer On-Peak kW	$ 4.409	per kW
	Non-Summer Remaining-Peak kW	$ 1.696	per kW
Delivery - Transmission	Summer On-Peak kW	$ 3.889	per kW
	Summer Remaining-Peak kW	$ 1.496	per kW
	Non-Summer On-Peak kW	$ 2.326	per kW
	Non-Summer Remaining-Peak kW	$ 0.895	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387	per kWh
Delivery Charge	$ 0.01279	Per kWh

	Summer	Non-Summer	
Generation On-Peak	$ 0.06589	$ 0.04873	per kWh
Generation Remaining	$ 0.06152	$ 0.04580	per kWh
Generation Off-Peak	$ 0.05424	$ 0.03809	per kWh

For billing demand purposes, the On-Peak and Remaining hours kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during the On-Peak and Remaining hours during each respective billing period, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8;

2. The minimum kW specified in the agreement for service or individual contract; or

3. 300 kW.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

Summer Billing Season: June through September billing cycles
Non-Summer Billing Season: October through May billing cycles

Seasonal billing charges will be applied to customer bills by monthly bill cycle. To the extent a billing cycle overlaps with a change in season under Time Period specified above, all usage during that billing cycle will be charged at the seasonal rates in effect at the time of that billing cycle.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. At the Company's option Customer will be required to sign the Company's standard agreement for service. If additional construction is required to serve the Customer, the contract period will be five years. If no additional distribution construction is required to serve the Customer, the contract period will be two years. At the end of these two-year service agreements, a Customer may request to modify the minimum kW in the standard agreement for service to reflect the Customer's actual usage during those two years.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for start-up and/or auxiliary load requirements for generation plants with a Power Supply capacity requirement of greater than 3 MW. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual Customer contract. This rate schedule may be used in conjunction with other applicable Company rate schedules; however, any service under this schedule is not eligible for Direct Access.

TYPE OF SERVICE

The type of service provided under this rate schedule shall be three-phase, 60 Hertz, at one standard voltage available within the vicinity of the Customer's site.

CHARGES

The bill will be the sum of the Basic Service Charge, Metering Service, Capacity Rate, and Power Supply Service below, including any applicable adjustments:

Basic Service Charge	$ 8,911.48	per month

Metering Service

The monthly metering charge will be 1.29% of the total metering cost specified in the Electric Supply Agreement between the Company and the Customer. This percentage will be reduced to 0.35% when the Customer provides all necessary metering equipment and is responsible for its replacement. The Customer will also be responsible for all applicable costs associated with communications facilities used to compile metered usage information.

Capacity Rate (only one applies)		
Secondary Voltage	$ 6.693	per kW
Primary Voltage	$ 6.457	per kW
Transmission Voltage	$ 2.090	per kW

Power Supply		
Hourly Pricing Proxy at the time of Station use		per kWh
Ancillary Service	$ 0.00074	per kWh

CONTRACT PERIOD

Any applicable contract periods will be set forth in an Electric Supply Agreement between the Customer and the Company.

CONNECTION COSTS

The Customer will pay all applicable connection costs and system improvement costs not otherwise covered in this schedule as a non-refundable contribution in aid of construction, including any associated tax liability.

POWER SUPPLY CAPACITY

Power Supply Capacity kW will be defined as the greater of:

(a) The amount of capacity (kW) reserved by the Customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of the Customer's generation unit(s) plus any necessary auxiliary load (including generation auxiliary load and/or any other load requirements at the plant site that would otherwise be provided by the Customer when the generation unit(s) are running).

If more than one generation unit is present at a single site, the Electric Supply Agreement may, at the Company's option, allow the Customer to start one unit at a time. In this instance, Power Supply Capacity kW will be defined as the greater of:

(a) The amount of capacity (kW) reserved by the Customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of one and only one Customer generation unit at any given time plus any necessary auxiliary load (including any or all generation auxiliary load and/or any other load requirements at the entire plant site that

would otherwise be provided by the Customer when any or all generation unit(s) are running).

If, during any one billing period, the highest 15 minute measured kW supplied by the Company (by voltage level) exceeds the amount of Power Supply Capacity specified in the Electric Supply Agreement, the Power Supply Capacity reservation (by voltage level) will be permanently increased to equal the higher measured kW. If the Company incurs additional connection costs to provide this added capacity, the Customer is responsible for payment of these costs as specified herein.

DETERMINATION OF HOURLY PRICING PROXY

Hourly pricing proxy will be calculated using the Palo Verde Peak or Off-Peak Intercontinental Exchange ("ICE") day ahead Price Index or successor. APS will calculate a weighted average using the day ahead hub pricing and volumes at Palo Verde, Four Corners, and Mead, for firm on-peak and off-peak prices as expressed on a per kWh basis, at the time Station Use power is supplied to the Customer.

METERING

The Company will normally install a supply meter at the point of delivery to the Customer and a generator meter(s) at the point(s) of output from each of the Customer's generators. However, the Customer can elect to supply this metering as long as it conforms to Company specifications. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by the Company.

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

3. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

4. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

5. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

INTERCONNECTION REQUIREMENTS

The Customer must meet all interconnection requirements as determined by the Company. The Customer is responsible for all costs associated with interconnection of the Customer's generation facility to the Company's system.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the Customer's bill. In addition, service may be subject to special terms and conditions as provided for in a Customer contract or service agreement.

AVAILABILITY

This rate schedule is applicable to Customers for Dusk to Dawn lighting for service to be rendered after December 1, 2021.

DESCRIPTION

The E-45 rate is available to Customers with Dusk to Dawn lights. These lights are on the Customer's property or a private street and the Customer is charged a monthly fee for the light. This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company.

TIME PERIOD

Dusk: Time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off the lights.

CHARGES

The monthly bill will consist of the fixture and energy charges, plus adjustments:

I. FIXTURES (Includes Mounting Arm, if applicable)

Fixture Equipment Class	Fixture Cost Range (per unit)	Company Owned Monthly Rate	Customer Owned Monthly Rate
A	$ 1 - $ 430	$ 6.61	$ 0.13
B	$ 431 - $ 520	$ 8.05	$ 0.15
C	$ 521 - $ 640	$ 9.66	$ 0.17
D	$ 641 - $ 820	$ 11.54	$ 0.22
E	$ 821 - $ 910	$ 14.60	$ 0.24
F	$ 911 - $ 1,010	$ 16.25	$ 0.27
G	$ 1,011 - $ 1,110	$ 17.77	$ 0.28
H	$ 1,111 - $ 1,250	$ 20.15	$ 0.30
I	$ 1,251 - $ 1,520	$ 22.41	$ 0.36
J	$ 1,521 - $ 1,670	$ 27.32	$ 0.39
K	$ 1,671 - $ 1,850	$ 30.37	$ 0.44

Note: Equipment cost greater than $ 1,850 shall be Customer Owned.

II. ENERGY (Includes Generation, T&D, RCS & SBC)

Monthly energy charges for new lighting fixtures will be determined by the Company using the following method:

kWh = Fixture Wattage x 344 Usage Hours
Generation = kWh per month x $ 0.07648
T&D, RCS, System Benefits = kWh per month x $ 0.03098

NOTES:

1. Company Owned fixtures are those fixtures that the Company installs, owns, maintains, and operates.

2. Customer Owned fixtures are those fixtures where the Customer owns and maintains the lighting fixtures, and the Company approves the installation and operates the fixtures.

3. APS has adopted LED lighting technology and LED lights do not include replaceable lamps (High Pressure Sodium Lights "HPS" were discontinued by most manufacturers).

4. Listed kWh reflects the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

5. kWh is determined by the company based on the rated wattage of the equipment and an established average hourly usage per month.

III. POLES

				CHARGES
			Height	Company Owned
A. Anchor Base Mounted	Round Steel	1 Simplex Adapter	12 ft.	$ 14.83
			22 ft.	$ 16.69
			25 ft	$ 18.07
			30 ft	$ 20.75
			32 ft	$ 21.80
	Round Steel	2 Simplex Adapters	12 ft.	$ 15.81
			22 ft.	$ 18.17
			25 ft.	$ 18.96
			30 ft.	$ 22.03
			32 ft.	$ 23.49
	Square Steel	5"	13 ft.	$ 17.00
			15 ft.	$ 15.19
			23 ft.	$ 18.02
			25 ft.	$ 19.81
			28 ft.	$ 21.99
			32 ft.	$ 21.87
	Concrete		12 ft.	$ 50.67
	Fiberglass		12 ft.	$ 42.91
	Decorative Transit	4"	16 ft.	$ 41.84
	Decorative Transit	6"	30 ft.	$ 80.78
	Hinged	Square	15 ft.	$ 16.08
		Round	19 ft.	$ 14.54
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$ 14.27
			22 ft.	$ 16.14
			25 ft.	$ 17.49
			30 ft.	$ 20.19
			32 ft.	$ 21.22
	Round Steel	2 Simplex Adapters	12 ft.	$ 15.24
			22 ft.	$ 17.03
			25 ft.	$ 18.38
			30 ft.	$ 21.46
			32 ft.	$ 22.92
		3 Bolt	32 ft.	$ 26.34
	Square Steel	5"	13 ft.	$ 16.45
			15 ft.	$ 16.82
			23 ft.	$ 17.45
			25 ft.	$ 19.26
			28 ft.	$ 21.39
			32 ft.	$ 22.21

III. POLES (cont.)

				CHARGES
			Height	Company Owned
C. Direct Bury	Round Steel		19 ft.	$ 22.44
			30 ft.	$ 17.52
			38 ft.	$ 21.38
		Self-Support	40 ft.	$ 26.34
		Stepped	25 ft.	$ 60.59
			32 ft.	$ 63.81
			49 ft.	$ 79.21
	Square Steel	4"	34 ft.	$ 19.34
		5"	20 ft.	$ 18.37
			30 ft.	$ 19.14
			38 ft.	$ 20.77
		8"	28 ft.	$ 34.66
			32 ft.	$ 36.24
	Decorative Transit		41 ft. 6 in.	$ 24.95
	Decorative Transit		47 ft.	$ 31.08
	Steel Distribution Pole (for lighting)		35 ft.	$ 28.69
D. Post Top	Decorative Transit Anchor		16 ft.	$ 42.74
	Gray Steel/Fiberglass		23 ft.	$ 14.82
	Black Steel		23 ft.	$ 16.33
			30 ft.	$ 10.90
			35 ft.	$ 10.90
E. Wood	Wood Poles		40 ft.	$ 15.52

NOTES:

1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.

2. Monthly charges for all new Company Owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary line if Customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in Section V below.

3. When adding lighting fixtures to an existing Company Owned or Customer Owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified in Section V below.

IV. ANCHOR BASE

			CHARGES
		Height	Company Owned
A. Flush		4 ft.	$ 12.07
		6 ft.	$ 14.40
B. Pedestal		8 ft.	$ 16.51
	For 32' Round Steel Pole only	4 ft. 6"	$ 11.45

V. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	CHARGE
	Company Owned
1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire, if Customer provides earthwork and conduit.	$ 4.26

VI. DETERMINATION OF CHARGES FOR NEW EQUIPMENT

Monthly charges for new lighting fixtures, poles and other equipment will be determined by the Company using the installed equipment multiplied by a monthly fixed charge rate specified in Section I or Section II above.

Any maintenance costs not designated within the E-45 Rate Schedule will be outlined in a maintenance agreement executed between the Company and the Customer.

TRIP CHARGE

A $ 150.00 trip charge per light will be charged when a Customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their dusk to dawn equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. The Customer is not authorized to make connections to the lighting circuits or to make attachments without prior notification to the Company. The Company may recalculate the rate or change the rate eligibility in such instances.

2. Should a Customer request relocation of a Dusk to Dawn lighting installation, the costs of such relocation will be paid by the Customer.

3. The Customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of photocontrols or fixtures) within ten (10) working days from notification by Customer. If the maintenance requires cable replacement or repairs, the Company will use reasonable efforts to complete said repairs within twenty (20) working days.

4. The Customer's bill will not be reduced due to photocontrol or cable repair or replacement outages.

5. The Customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

6. Lighting equipment, which is not specified in this rate schedule, will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

7. Lighting Equipment and services with an initial Company cost exceeding $25,000 will require a financial liability agreement between the Company and the Customer.

8. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill. In addition, service may be subject to special terms and conditions as provided for in a Customer contract or service agreement.

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the Customer requests any non-standard Dusk to Dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the Customer will own, operate, and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Monthly bills rendered for non-standard facilities will consist of the following rates, plus any adjustments incorporated in this schedule. KWh will be determined by the Company, based on the rated wattage of the equipment and an estimated average hourly usage per month.

A.	Service Charge	$ 4.09	per installed fixture per month
B.	Energy Charge	$ 0.07949	per kWh per month

CONTRACT PERIOD

All Dusk to Dawn lighting installations will require a written agreement for service for a minimum of ten (10) years from the date of initial delivery of service. It shall continue in effect thereafter, unless terminated by either party on thirty (30) days' written notice.

AVAILABILITY

This rate schedule is applicable to Customers for Dusk to Dawn lighting.

This rate schedule is frozen as of December 1, 2021. This means a Customer that was already taking service under this rate schedule before that date may continue service under this rate schedule, but no Customers connecting service after that date will be eligible to choose to be served under this rate schedule.

DESCRIPTION

The E-47 rate is available to Customers with Dusk to Dawn lights. These lights are on the Customer's property or a private street, and the Customer is charged a monthly fee for the light. This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company.

TIME PERIOD

Dusk: The time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

I. FIXTURES (Includes Mounting Arm, if Applicable)

				CHARGES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
A. Acorn	3,835 LED	75	26	$24.48	$3.10
	4,796 LED	75	26	$19.66	$3.04
	5,003 LED	100	35	$26.53	$4.09
	5,904 LED	100	35	$26.06	$4.09
	6,000 IND	85	29	$21.77	$3.37
B. Architectural	6,200 IND	85	29	$11.46	$3.37
	8,400 IND	100	34	$12.09	$3.84
	10,200 IND	120	41	$13.30	$4.47
	13,000 IND	150	52	$14.68	$5.48

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				CHARGES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
B. Architectural (cont.)	20,500 IND	200	69	$16.73	$7.05
	22,500 IND	265	91	$19.95	$9.07
	3,300 LED	43	15	$11.59	$1.77
	3,800 LED	32	12	$8.74	$1.41
	3,900 LED	32	12	$11.27	$1.44
	4,050 LED	63	22	$21.08	$2.63
	4,100 LED	45	16	$11.70	$1.88
	4,800 LED	41	15	$9.36	$1.74
	5,000 LED	41	15	$10.87	$1.76
	5,100 LED	60	21	$11.52	$2.40
	5,300 LED	67	24	$11.85	$2.73
	5,800 LED	94	32	$20.15	$3.65
	5,890 LED	89	31	$23.26	$3.62
	6,000 LED	62	22	$21.08	$2.63
	6,000 LED	67	24	$22.50	$2.86
	6,810 LED	101	35	$21.37	$4.03
	7,100 LED	62	22	$22.29	$2.65
	7,400 LED	127	44	$23.10	$4.75
	7,500 LED	73	26	$22.72	$3.07
	7,700 LED	86	30	$20.83	$3.49
	8,200 LED	88	31	$11.83	$3.48
	8,200 LED	95	33	$13.43	$3.70
	8,300 LED	72	25	$20.28	$2.95
	8,300 LED	106	37	$14.08	$4.14
	8,500 LED	88	31	$13.23	$3.50
	9,020 LED	139	48	$25.96	$5.44
	9,900 LED	130	45	$15.64	$5.00
	10,000 LED	93	32	$24.25	$3.73
	10,000 LED	113	39	$15.00	$4.37
	10,600 LED	126	44	$25.53	$5.01
	11,100 LED	108	38	$14.44	$4.24
	11,500 LED	108	38	$14.89	$4.25
	12,300 LED	203	70	$28.83	$7.14
	12,900 LED	119	41	$25.24	$4.69
	13,260 LED	202	70	$30.67	$7.85
	14,000 LED	171	59	$29.50	$6.68
	15,000 LED	136	47	$28.21	$5.38
	15,400 LED	144	50	$28.52	$5.71
	18,300 LED	162	56	$18.25	$6.21
	19,200 LED	257	89	$30.40	$9.86
	20,000 LED	258	89	$30.40	$9.86
	20,300 LED	193	67	$19.43	$7.39

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					CHARGES	
		Lumen	Watts	kWh	Company Owned	Customer Owned
B. Architectural (cont.)		21,000 LED	193	67	$28.02	$7.49
C. Cobra		6,200 IND	75	26	$11.92	$3.10
		6,400 IND	85	29	$10.15	$3.37
		8,000 IND	88	30	$11.85	$3.47
		8,400 IND	100	34	$10.97	$3.84
		10,200 IND	120	41	$11.82	$4.47
		13,000 IND	150	52	$13.01	$5.48
		15,250 IND	200	69	$15.69	$7.05
		22,500 IND	250	86	$20.99	$8.59
	Gray/Bronze	3,500 IND	55	19	$11.87	$2.45
		6,000 LED	95	33	$19.29	$3.74
		8,700 LED	142	49	$21.69	$5.21
		9,600 LED	157	54	$23.08	$5.67
		11,600 LED-B	181	62	$21.53	$6.39
	Gray/Bronze	3,300 LED	43	15	$10.19	$2.08
	Gray/Bronze	5,300 LED	67	23	$11.83	$2.82
	Gray/Bronze	8,300 LED	106	37	$15.33	$4.11
	Gray/Bronze	10,500 LED	130	45	$17.06	$4.84
	Gray/Bronze	20,000 LED	258	89	$29.65	$8.89
D. Decorative Transit		5,300 LED	75	26	$32.18	$3.10
		8,300 LED	100	34	$34.46	$3.84
		8,147 LED	75	26	$40.46	$3.30
		9,522 LED	100	35	$40.89	$4.26
		10,500 LED	150	52	$36.99	$5.48
		14,896 LED	150	52	$45.23	$6.12
	Double	8,147 LED	75	26	$73.25	$3.53
	Double	9,522 LED	100	35	$73.16	$4.51
	Double	14,896 LED	100	52	$79.96	$6.33
	Copper	6,000 IND	85	29	$21.35	$3.37
	Gray/Black	8,000 IND	88	30	$16.82	$3.47
	Gray/Black	4,350 LED	86	30	$15.25	$3.47
E. Flood		14,470 LED	148	51	$27.08	$5.80
		16,000 LED	125	43	$26.22	$4.93
F. Pendant		8,678 LED	75	26	$29.82	$3.17
		13,964 LED	100	35	$31.50	$4.15
G. Post Top		4,350 LED	86	30	$15.19	$3.41
		6,400 LED	30	30	$15.19	$3.41
		6,600 LED	83	29	$15.09	$3.29
H. Roadway		3,300 LED	43	15	$10.71	$1.76
		3,800 LED	32	12	$8.19	$1.41
		3,900 LED	32	12	$10.38	$1.43
		4,100 LED	45	16	$10.81	$1.87

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				CHARGES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
H. Roadway (cont.)	4,800 LED	41	15	$8.78	$1.73
	5,000 LED	41	15	$10.32	$1.76
	5,100 LED	60	21	$10.96	$2.40
	5,300 LED	67	24	$11.30	$2.73
	8,200 LED	88	31	$11.00	$3.47
	8,200 LED	95	33	$12.86	$3.69
	8,300 LED	106	37	$13.28	$4.12
	8,500 LED	88	31	$12.65	$3.49
	9,900 LED	130	45	$15.06	$4.99
	10,000 LED	113	39	$14.43	$4.35
	11,100 LED	108	38	$13.61	$4.24
	11,500 LED	108	38	$14.31	$4.24
	18,300 LED	162	56	$17.23	$6.19
	19,200 LED	257	89	$21.62	$9.75
	20,000 LED	258	89	$21.62	$9.75
	20,300 LED	193	67	$18.41	$7.37
	21,000 LED	193	67	$19.24	$7.38
Acorn	4,000 INC	295	103	$11.92	$6.67
	7,000 MV	175	73	$8.86	$15.44
	20,000 MV	400	150	$30.37	$17.21
	9,500 HPS	100	41	$32.97	$11.24
	16,000 HPS	150	69	$36.61	$14.20
Architectural	9,500 HPS	100	41	$18.74	$8.70
	16,000 HPS	150	69	$21.88	$11.97
	30,000 HPS	250	99	$25.97	$15.35
	50,000 HPS	400	153	$32.04	$22.10
	14,000 MH	175	72	$26.22	$14.37
	21,000 MH	250	101	$29.77	$17.72
	36,000 MH	400	159	$37.22	$24.37
	8,000 LPS	55	30	$27.25	$11.97
	13,500 LPS	90	50	$32.12	$14.44
	22,500 LPS	135	72	$36.70	$17.60
	33,000 LPS	180	90	$44.14	$20.73
Cobra Roadway	5,800 HPS	70	29	$10.64	$6.30
	9,500 HPS	100	41	$12.52	$7.70
	16,000 HPS	150	69	$15.69	$10.75
	30,000 HPS	250	99	$18.92	$13.98
	50,000 HPS	400	153	$25.67	$19.95
	14,000 MH	175	72	$18.24	$12.43
	21,000 MH	250	101	$21.31	$15.47
	36,000 MH	400	159	$28.07	$21.49
	8,000 FL	100	38	$20.97	$6.15

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		Lumen	Watts	kWh	CHARGES Company Owned	CHARGES Customer Owned
Decorative Transit		9,500 HPS	100	41	$45.20	$13.53
		16,000 HPS	150	69	$44.95	$7.69
		30,000 HPS	250	99	$51.75	$19.53
Flood		30,000 HPS	250	99	$25.11	$15.61
		50,000 HPS	400	153	$31.15	$21.66
		21,000 MH	250	101	$26.80	$16.50
		36,000 MH	400	159	$32.69	$22.35
Post Top		8,000 FL	100	38	$22.59	$6.38
	Colonial	9,500 HPS	100	41	$12.93	$8.10
	Colonial	9,500 HPS	100	41	$14.88	$8.39
	Decorative	9,500 HPS	100	41	$39.56	$12.48
Brackets over 8 ft. and up to 16 ft. in length					$2.09	—

The following lamps will be available for 90 days following the effective date of revision 57. At that time, these lamps will be frozen consistent with all other elements of the rate schedule.

	Lumens	Watts	kWh	CHARGES Company Owned	CHARGES Customer Owned
ARCHITECTURAL/RW BRONZE	4,300 LED	45	16	$11.94	$1.92
	20,100 LED	174	60	$19.07	$6.78
	21,000 LED	174	60	$27.85	$6.88
COBRA/GRAY	20,100 LED	174	60	$18.03	$6.76
	21,000 LED	174	60	$18.89	$6.77
ROADWAY/GRAY	4,300 LED	45	16	$11.31	$1.91
	5,400 LED	60	21	$11.19	$2.45
	8,600 LED	95	33	$13.12	$3.77
POST TOP/SALEM BLACK	6,400 LED	83	29	$14.43	$3.35
	4,350 LED	86	30	$14.54	$3.47
TOWN AND COUNTRY/GRAY	5,600 LED	56	20	$10.58	$2.33
TOWN AND COUNTRY/BLACK	5,600 LED	56	20	$10.58	$2.33
DECORATIVE TRANSIT/SINGLE	3,720 LED	37	13	$44.83	$2.01

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ROADWAY ARCHITECTURAL -BRONZE	3,408 LED	31	11	$9.68	$1.34
	4,800 LED	43	15	$10.12	$1.78
	4,900 LED	43	15	$9.95	$1.78
	7,810 LED	68	24	$12.95	$2.80
	8,165 LED	68	24	$12.94	$2.80
	11,000 LED	96	34	$14.08	$3.89
	11,500 LED	98	34	$14.03	$3.89
COBRA ROADWAY/GRAY	3,408 LED	31	11	$8.95	$1.33
	4,800 LED	43	15	$9.39	$1.77
	4,900 LED	43	15	$9.45	$1.77
	7,810 LED	68	24	$12.02	$2.78
	8,165 LED	68	24	$12.24	$2.78
	11,000 LED	96	34	$13.16	$3.88
	11,500 LED	96	34	$13.04	$3.88
FLOOD	14,500 LED	96	34	$16.99	$3.93

NOTES:

1. Company Owned fixtures are those fixtures that the Company installs, owns, and operates.

2. Customer Owned fixtures are those fixtures where the Customer owns and maintains the lighting fixtures, and the Company approves the installation, operates the fixtures, and replaces Company standard lamps only. The Company may replace standard lamps if it has a maintenance agreement with the customer.

3. Listed kWh reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

4. HPS = High Pressure Sodium

5. MH = Metal Halide

6. LPS = Low Pressure Sodium

7. FL = Fluorescent

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8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those Customers being served and those installations in service on April 21, 1983.

9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those Customers being served and those installation in service on June 1, 1987 in accordance with A.R.S. §49-1104(A).

10. LED = Light Emitting Diode

11. IND = Induction

13. B-LED = Beta Light Emitting Diode

II. POLES

			CHARGES	
			Height	Company Owned
A. Anchor Base Mounted	Round Steel	1 Simplex Adapter	12 ft.	$14.83
			22 ft.	$16.69
			25 ft.	$18.07
			30 ft.	$20.75
			32 ft.	$21.80
	Round Steel	2 Simplex Adapters	12 ft.	$15.81
			22 ft.	$18.17
			25 ft.	$18.96
			30 ft.	$22.03
			32 ft.	$23.49
	Square Steel	5"	13 ft.	$17.00
			15 ft.	$15.19
			23 ft.	$18.02
			25 ft.	$19.81
			28 ft.	$21.99
			32 ft.	$21.87
	Concrete		12 ft.	$50.67
	Fiberglass		12 ft.	$42.91
	Decorative Transit	4"	16 ft.	$41.84
	Decorative Transit	6"	30 ft.	$80.78
	Hinged	Square	15 ft.	$16.08
		Round	19 ft.	$14.54
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$14.27
			22 ft.	$16.14
			25 ft.	$17.49

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				CHARGES
			Height	Company Owned
B. Anchor Base Mounted			30 ft.	$20.19
			32 ft.	$21.22
	Round Steel	2 Simplex Adapters	12 ft.	$15.24
			22 ft.	$17.03
			25 ft.	$18.38
			30 ft.	$21.46
			32 ft.	$22.92
		3 Bolt Arm	32 ft.	$26.34
	Square Steel	5"	13 ft.	$16.45
			15 ft.	$16.82
			23 ft.	$17.45
			25 ft.	$19.26
			28 ft.	$21.39
			32 ft.	$22.21
C. Direct Bury	Round Steel		19 ft.	$22.44
			30 ft.	$17.52
			38 ft.	$21.38
		Self-Support Stepped	40 ft.	$26.34
			25 ft.	$60.59
			32 ft.	$63.81
			49 ft.	$79.21
	Square Steel	4"	34 ft.	$19.34
		5"	20 ft.	$18.37
			30 ft.	$19.14
			38 ft.	$20.77
		8"	28 ft.	$34.66
			32 ft.	$36.24
	Decorative Transit		41 ft. 6 in.	$24.95
	Decorative Transit		47 ft.	$31.08
	Steel Distribution Pole (for lighting)		35 ft.	$28.69
D. Post Top	Decorative Transit Anchor		16 ft.	$42.74
	Gray Steel/Fiberglass		23 ft.	$14.82
	Black Steel		23 ft.	$16.33
	Wood Poles		30 ft.	$10.90
			35 ft.	$10.90
			40 ft.	$15.52

NOTES: 1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.

2. Monthly charges for all new Company Owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary

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line if Customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in Section IV.1 below.

3. When adding lighting fixtures to an existing Company Owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified in Section IV.1 below.

4. Any and all distribution wire required to serve lighting facilities placed on a Customer Owned pole, whether new or existing, is subject to the additional monthly wire charges specified in Section IV.1 below.

III. ANCHOR BASE

		CHARGES
	Height	Company Owned
A. Flush	4 ft.	$12.07
	6 ft.	$14.40
B. Pedestal	8 ft.	$16.51
For 32' Round Steel Pole only	4 ft. 6"	$11.45

IV. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	CHARGE
	Company Owned
1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire, if Customer provides earthwork and conduit.	$4.26
2. Additional maintenance charge for HPS lamp and luminaire that is not accessible by bucket truck.	$3.41
3. Additional maintenance charge for MH lamp and luminaire that is not accessible by bucket truck.	$7.37

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V. DETERMINATION OF CHARGES FOR NEW EQUIPMENT

Monthly charges for new lighting fixtures, poles and other equipment not included in Sections I, II, or III above will be determined by the Company using the following method:

Step 1 Determination of monthly charges for each charge type

Charge Type	Monthly Charge		Cost Inputs		PV Factor		Monthly Fixed Charge Rate
1	Carrying cost (fixtures)	=	Equipment cost (installed)	x	NA	x	1.518%
2	Lighting O&M	=	O&M cost (lifecycle)	x	0.427	x	1.518%
3	Carrying cost (poles)	=	Equipment cost (installed)	x	NA	x	1.296%

Charge Type	Monthly Charge		kWh Input		$/kWh
4	Generation	=	kWh per month	x	0.07676
5	T&D, RCS, system benefits	=	kWh per month	x	0.03126

Step 2 Determination of Total Monthly Charge
The total monthly charge will be the summation of the charges for each applicable charge type.

Equipment	Charge Type
Fixtures - Company Owned	1,2,4,5
Fixtures - Customer Owned	2,4,5
Poles - Company Owned	3

TRIP CHARGE

A $100.00 trip charge per light will be charged when a Customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their dusk to dawn equipment.

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ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. The 4,000 and 7,000 lumen lamps use an open glass diffuser. All units are controlled by a photoelectric switch.

2. The Customer is not authorized to make connections to the lighting circuits or to make attachments without prior notification to the Company. The Company may recalculate the rate or change the rate eligibility in such instances.

3. Should a Customer request relocation of a Dusk to Dawn lighting installation, the costs of such relocation will be paid by the Customer.

4. The Customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by Customer. If the maintenance requires cable replacement or repairs, the Company will use reasonable efforts to complete said repairs within twenty (20) working days.

5. The Customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

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6. The Customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment, multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

7. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

8. Lighting Equipment and services with an initial Company cost exceeding $25,000 will require a financial liability agreement between the Company and the Customer.

9. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the Customer requests any non-standard Dusk to Dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the Customer will own, operate and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Monthly bills rendered for non-standard facilities will consist of the following rates, plus any adjustments incorporated in this schedule. KWh will be determined by the Company, based on the rated wattage of the equipment and an estimated average hourly usage per month.

A.	Service Charge	$ 4.09	per installed fixture per month
B.	Energy Charge	$ 0.07949	per kWh per month

CONTRACT PERIOD

All Dusk to Dawn lighting installations will require a written agreement for service for a minimum of ten (10) years, or longer at Company's option.

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AVAILABILITY

This rate schedule is applicable to those portions of cities, towns and unincorporated communities in which the Company does a general retail electric business and where the Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

This rate schedule is frozen as of December 1, 2021. This means a Customer that was already taking service under this rate schedule before that date may continue service under this rate schedule, but no Customers connecting service after that date will be eligible to be served under this rate schedule.

DESCRIPTION

E-58 is a rate that is applicable for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of Company's facilities.

TIME PERIODS

Dusk: Time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

CHARGES

The monthly bill will consist of the following charges, plus adjustments.

I. FIXTURES (Includes Mounting Arm, if Applicable)

				CHARGES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
A. Acorn	3,835 LED	75	26	$25.12	$8.80
	4,796 LED	75	26	$20.17	$7.49
	5,003 LED	100	35	$27.23	$10.10
	5,904 LED	100	35	$26.75	$9.97
	6000 IND	85	29	$22.34	$5.95
B. Architectural	6,200 IND	85	29	$11.75	$4.55
	8,400 IND	100	34	$12.40	$5.05
	10,200 IND	120	41	$13.64	$5.78
	13,000 IND	150	52	$15.06	$6.87
	20,500 IND	200	69	$17.16	$8.55

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				CHARGES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
B. Architectural (cont.)	22,500 IND	265	91	$20.47	$10.76
	3,300 LED	43	15	$11.88	$4.38
	3,800 LED	32	12	$8.96	$3.37
	3,900 LED	32	12	$11.56	$4.06
	4,050 LED	63	22	$21.63	$7.56
	4,100 LED	45	16	$12.00	$4.50
	4,800 LED	41	15	$9.59	$3.78
	5,000 LED	41	15	$11.14	$4.19
	5,100 LED	60	21	$11.81	$4.84
	5,300 LED	67	24	$12.15	$5.19
	5,800 LED	94	32	$20.67	$5.97
	5,890 LED	89	31	$23.88	$8.88
	6,000 LED	62	22	$21.63	$7.56
	6,000 LED	67	24	$23.09	$8.11
	6,400 LED	89	31	$20.77	$5.91
	6,810 LED	101	35	$21.93	$8.70
	7,100 LED	62	22	$22.88	$7.88
	7,400 LED	127	44	$23.71	$7.35
	7,500 LED	73	26	$23.32	$8.32
	7,700 LED	86	30	$21.37	$8.14
	8,200 LED	88	31	$12.13	$5.76
	8,200 LED	95	33	$13.78	$6.35
	8,300 LED	72	25	$20.81	$7.59
	8,300 LED	106	37	$14.44	$6.85
	8,500 LED	88	31	$13.56	$6.14
	9,020 LED	139	48	$26.64	$10.99
	9,200 LED	139	48	$29.74	$8.46
	9,900 LED	130	45	$16.04	$7.93
	10,000 LED	93	32	$24.88	$9.23
	10,000 LED	113	39	$15.39	$7.28
	10,600 LED	126	44	$26.20	$10.54
	11,100 LED	108	38	$14.81	$7.04
	11,500 LED	108	38	$15.27	$7.16
	12,300 LED	203	70	$29.59	$10.27
	12,900 LED	119	41	$25.90	$10.23
	13,260 LED	202	70	$31.48	$14.06
	13,620 LED	202	70	$33.09	$10.72
	14,000 LED	171	59	$30.28	$12.85
	15,000 LED	136	47	$28.95	$11.54
	15,400 LED	144	50	$29.27	$11.86
	18,300 LED	162	56	$18.73	$9.53
	19,200 LED	257	89	$31.21	$15.53
	20,000 LED	258	89	$31.21	$15.53

FROZEN

					CHARGES	
		Lumen	Watts	kWh	Investment by Company	Investment by Others
B. Architectural (cont.)		20,300 LED	193	67	$19.94	$10.74
		21,000 LED	193	67	$28.76	$13.09
C. Cobra		6,200 IND	75	26	$12.22	$4.36
		6,400 IND	85	29	$10.41	$4.37
		8,000 IND	88	30	$12.15	$4.68
		8,400 IND	100	34	$11.25	$4.90
		10,200 IND	120	41	$12.12	$5.57
		13,000 IND	150	52	$13.34	$6.64
		15,250 IND	200	69	$16.09	$8.40
		22,500 IND	250	86	$21.54	$10.50
	Gray/Bronze	3,500 IND	55	19	$12.18	$3.78
		6,000 LED	95	33	$19.79	$5.94
		8,700 LED	142	49	$22.26	$7.57
		9,600 LED	157	54	$23.69	$8.17
		11,600 B-LED	181	62	$22.10	$8.63
	Gray/Bronze	3,300 LED	43	15	$10.44	$3.22
	Gray/Bronze	5,300 LED	67	23	$12.13	$4.10
	Gray/Bronze	8,300 LED	106	37	$15.72	$5.72
	Gray/Bronze	10,500 LED	130	45	$17.50	$6.59
	Gray/Bronze	20,000 LED	258	89	$30.44	$11.92
D. Decorative Transit		5,300 LED	75	26	$33.03	$7.09
		8,300 LED	100	34	$35.37	$8.08
		8,147 LED	75	26	$41.54	$13.19
		9,522 LED	100	35	$41.98	$14.03
		10,500 LED	150	52	$37.97	$9.89
		14,896 LED	150	52	$46.44	$16.59
	Double	8,147 LED	75	26	$75.21	$22.01
	Double	9,522 LED	100	35	$75.13	$22.74
	Double	14,896 LED	100	52	$82.11	$25.92
	Copper	6,000 IND	85	29	$21.91	$5.90
	Gray/Black	8,000 IND	88	30	$17.25	$5.35
	Gray/Black	4,350 LED	86	30	$15.64	$5.14
E. Flood		14,470 LED	148	51	$27.79	$11.55
		16,000 LED	125	43	$26.91	$10.66
F. Pendant		8,678 LED	75	26	$30.61	$10.27
		13,964 LED	100	35	$32.33	$11.46
G. Post Top		4,350 LED	86	30	$15.58	$6.59
		6,400 LED	30	30	$15.58	$6.59
		6,600 LED	83	29	$15.48	$6.48
H. Roadway		3,300 LED	43	15	$10.98	$4.14
		3,800 LED	32	12	$8.39	$3.22
		3,900 LED	32	12	$10.65	$3.81

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				CHARGES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
H. Roadway (cont.)	4,100 LED	45	16	$11.09	$4.25
	4,800 LED	41	15	$9.00	$3.62
	5,000 LED	41	15	$10.58	$4.04
	5,100 LED	60	21	$11.24	$4.70
	5,300 LED	67	24	$11.58	$5.03
	8,200 LED	88	31	$11.28	$5.52
	8,200 LED	95	33	$13.19	$6.19
	8,300 LED	106	37	$13.62	$6.62
	8,500 LED	88	31	$12.97	$5.97
	9,900 LED	130	45	$15.45	$7.76
	10,000 LED	113	39	$14.80	$7.11
	11,100 LED	108	38	$13.96	$6.81
	11,500 LED	108	38	$14.68	$7.00
	18,300 LED	162	56	$17.68	$9.26
	19,200 LED	257	89	$22.19	$13.14
	20,000 LED	258	89	$22.19	$13.14
	20,300 LED	193	67	$18.89	$10.47
	21,000 LED	193	67	$19.75	$10.69
Acorn	4,000 INC	295	103	$12.22	$6.83
	7,000 MV	175	73	$15.84	$9.08
	11,000 MV	250	96	$19.84	$12.11
	20,000 MV	400	150	$31.17	$17.66
	9,500 HPS	100	41	$33.84	$11.52
	16,000 HPS	150	69	$37.58	$14.56
Architectural	9,500 HPS	100	41	$19.22	$9.16
	16,000 HPS	150	69	$22.95	$22.45
	30,000 HPS	250	99	$26.65	$15.75
	50,000 HPS	400	153	$32.89	$22.68
	14,000 MH	175	72	$26.91	$14.74
	21,000 MH	250	101	$30.56	$18.18
	36,000 MH	400	159	$38.21	$25.01
	8,000 LPS	55	30	$27.97	$12.27
	13,500 LPS	90	50	$32.98	$14.81
	22,500 LPS	135	72	$37.67	$18.06
	33,000 LPS	180	90	$45.31	$21.28
Cobra	5,800 HPS	70	29	$10.91	$6.45
	9,500 HPS	100	41	$12.84	$7.89
Roadway	16,000 HPS	150	69	$16.09	$11.03
	30,000 HPS	250	99	$19.41	$14.34

FROZEN

					CHARGES	
		Lumen	Watts	kWh	Investment by Company	Investment by Others
Cobra Roadway		50,000 HPS	400	153	$26.34	$20.47
		14,000 MH	175	72	$18.71	$12.75
		21,000 MH	250	101	$21.87	$15.87
		36,000 MH	400	159	$28.81	$22.05
		8,000 FL	100	38	$21.51	$6.29
Decorative Transit		9,500 HPS	100	41	$46.41	$13.87
		16,000 HPS	150	69	$46.15	$15.51
		30,000 HPS	250	99	$53.13	$20.04
Flood		30,000 HPS	250	99	$25.77	$16.01
		50,000 HPS	400	153	$31.98	$22.23
		21,000 MH	250	101	$27.51	$16.92
		36,000 MH	400	159	$33.56	$22.94
Post Top	Colonial Gray	8,000 FL	100	38	$23.19	$6.53
	Colonial Gray	9,500 HPS	100	41	$13.26	$8.30
	Colonial Black	9,500 HPS	100	41	$15.26	$8.59
	Decorative	9,500 HPS	100	41	$40.62	$12.79

The following lamps will be available for 90 days following the effective date of revision 55. At that time these lamps will be frozen consistent with all other elements of this schedule.

				CHARGES	
	Lumens	Watts	kWh	Investment by Company	Investment by Others
ARCHITECTURAL/RW BRONZE	4,300 LED	45	16	$12.25	$ 4.60
	20,100 LED	174	60	$19.57	$ 10.18
	21,000 LED	174	60	$28.59	$ 12.58
COBRA/GRAY	20,100 LED	174	60	$18.50	$ 9.90
	21,000 LED	174	60	$19.38	$ 10.14
ROADWAY/GRAY	4,300 LED	45	16	$11.60	$ 4.42
	5,400 LED	60	21	$11.48	$ 4.80
ROADWAY	8,600 LED	95	33	$13.46	$ 6.32
POST TOP/SALEM BLACK	6,400 LED	83	29	$14.80	$ 6.34
	4,350 LED	86	30	$14.92	$ 6.46
TOWN AND COUNTRY/GRAY	5,600 LED	56	20	$10.85	$ 4.56
TOWN AND COUNTRY/BLACK	5,600 LED	56	20	$10.85	$ 4.56

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DECORATIVE TRANSIT/SINGLE	3,720 LED	37	13	$46.03	$ 13.35
ROADWAY ARCHITECTURAL -BRONZE	3,408 LED	31	11	$9.92	$ 3.56
	4,800 LED	43	15	$10.37	$ 4.01
	4,900 LED	43	15	$10.20	$ 3.97
	7,810 LED	68	24	$13.28	$ 5.53
	8,165 LED	68	24	$13.27	$ 5.53
	11,000 LED	96	34	$14.44	$ 6.67
	11,500 LED	98	34	$14.40	$ 6.66
COBRA ROADWAY/GRAY	3,408 LED	31	11	$9.18	$ 3.36
	4,800 LED	43	15	$9.63	$ 3.81
	4,900 LED	43	15	$9.69	$ 3.82
	7,810 LED	68	24	$12.33	$ 5.28
	8,165 LED	68	24	$12.56	$ 5.33
	11,000 LED	96	34	$13.49	$ 6.41
	11,500 LED	96	34	$13.38	$ 6.39
FLOOD	14,500 LED	96	34	$17.43	$ 7.47

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.

2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the Customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.

3. Listed kWh reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

4. HPS = High Pressure Sodium

5. MH = Metal Halide

PROPOSED

6. LPS = Low Pressure Sodium

7. FL = Fluorescent

8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those Customers being served and those installations in service on November 1, 1986.

9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those Customers being served and those installation in service on November 1, 1986 in accordance with A.R.S. §49-1104(A).

10. LED = Light Emitting Diode

11. IND = Induction

II. POLES

				CHARGES	
			Height	Investment by Company	Investment by Others
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$15.21	$2.08
			22 ft.	$17.12	$2.34
			25 ft.	$18.54	$2.54
			30 ft.	$21.29	$2.91
			32 ft.	$22.37	$2.95
		2 Simplex Adapters	12 ft.	$16.22	$2.22
			22 ft.	$18.64	$2.55
			25 ft.	$19.45	$2.66
			30 ft.	$22.61	$3.10
			32 ft.	$24.11	$3.31
	Square Steel	5"	13 ft.	$17.44	$2.38
			15 ft.	$15.58	$2.13
			23 ft.	$18.49	$2.53
			25 ft.	$20.33	$2.78
			28 ft.	$22.57	$3.09
			32 ft.	$22.44	$3.08
	Concrete		12 ft.	$52.03	$7.15
	Fiberglass		12 ft.	$44.06	$6.04
	Decorative Transit	4"	16 ft.	$42.95	$5.91
	Decorative Transit	6"	30 ft.	$82.95	$11.41
	Hinged Poles	Square	15 ft.	$16.50	$1.33
		Round	19 ft.	$14.92	$1.20

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				CHARGES	
			Height	Investment by Company	Investment by Others
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$14.63	$1.99
			22 ft.	$16.55	$2.26
			25 ft.	$17.94	$2.46
			30 ft.	$20.72	$2.85
			32 ft.	$21.78	$2.98
		2 Simplex Adapters	12 ft.	$15.63	$2.13
			22 ft.	$17.47	$2.38
			25 ft.	$18.86	$2.57
			30 ft.	$22.02	$3.01
			32 ft.	$23.52	$3.22
		3 Bolt	32 ft.	$27.03	$3.69
	Square Steel	5"	13 ft.	$16.88	$2.32
			15 ft.	$17.25	$2.34
			23 ft.	$17.91	$2.46
			25 ft.	$19.76	$2.72
			28 ft.	$21.95	$3.01
			32 ft.	$22.80	$3.10
C. Direct Bury	Round Steel		19 ft.	$23.03	$3.16
			30 ft.	$17.98	$3.31
			38 ft.	$21.94	$3.40
		Self Stepped	40 ft.	$27.03	$4.26
			25 ft.	$62.21	$5.06
			32 ft.	$65.52	$5.33
			49 ft.	$81.34	$11.19
	Square Steel	4"	34 ft.	$19.84	$3.42
		5"	20 ft.	$18.84	$3.10
			30 ft.	$19.64	$3.22
			38 ft.	$21.31	$3.68
		8"	28 ft.	$35.59	$2.87
			32 ft.	$37.20	$3.03
	Decorative Transit		41 ft 6	$25.61	$3.74
	Decorative Transit		47 ft.	$31.91	$4.68
	Steel Distribution Pole (for lighting only)		35 ft.	$29.45	$3.86
D. Post Top	Decorative Transit Anchor Base		16 ft.	$43.88	$6.01
	Gray Steel/Fiberglass		23 ft.	$15.20	$2.48
	Black Steel		23 ft.	$16.76	$2.74
E. Existing distribution pole suitable for streetlight use				$1.83	
F. FROZEN	Wood Poles		30 ft.	$11.20	$1.95
			35 ft.	$11.20	$1.85

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NOTE: The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the Customer provides earthwork and conduit (excluding the underground to overhead transition).

III. ANCHOR BASE

	Height	CHARGES	
		Investment by Company	Investment by Others
A. Flush	4 ft.	$12.38	$1.69
	6 ft.	$14.78	$2.54
B. Pedestal	8 ft.	$16.93	$2.93
For 32' Round Steel Pole only	4 ft. 6"	$11.74	$2.01

IV. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	CHARGE
	Company Owned
Underground Circuit Charges:	
a. Per foot of cable, installed under paving	$0.19757
b. Per foot of cable, not installed under paving	$0.06973

FROZEN

V. DETERMINATION OF CHARGES FOR NEW EQUIPMENT

Monthly charges for new lighting fixtures, poles and other equipment not included in Sections I, II, or III above will be determined by the Company using the following method:

Step 1 Determination of Charges for each Charge Type

Charge Type	Monthly Charge		Cost Inputs		PV Factor		Monthly Fixed Charge Rate
1	Carrying Cost (fixtures)	=	Equipment Cost (installed)	x	NA	x	1.518%
2	Carrying Cost (poles)	=	Equipment Cost (installed)	x	NA	x	1.296%
3	Fixture Replacement Cost	=	Equipment Cost (installed)	x	0.257	x	1.518%
4	Pole, Anchor Replacement Cost	=	Equipment Cost (installed)	x	0.110	x	1.296%
5	Lighting O&M	=	O&M Cost (lifecycle)	x	0.427	x	1.518%

Charge Type	Monthly Charge		kWh Input		$/kWh
6	Generation	=	kWh per month	x	$0.07856
7	T&D, RCS, SB	=	kWh per month	x	$0.03182

Step 2 Determination of Total Monthly Charge

The total monthly charge will be the summation of the charges for each applicable charge type

Equipment	Charge Type
Fixture - IBC	1,5,6,7
Fixture - IBO	3,5,6,7
Pole, Anchor Base - IBC	2
Pole, Anchor Base - IBO	4

EFFECTIVE

TRIP CHARGE

A $100.00 trip charge per light will be charged when a Customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street lighting equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.
2. The Customer will be responsible for notifying the Company when the streetlighting facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by Customer. If the maintenance requires cable replacement or repairs, the Company will use reasonable efforts to complete said repairs within twenty (20) working days.

PROPOSED

3. The Customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

4. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

5. Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

6. The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the Customer. When the extension is underground the customer will provide earthwork as specified in the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

7. Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

8. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

PROPOSED

AVAILABILITY

This rate schedule is available for government owned outdoor lighting.

DESCRIPTION

This rate schedule is applicable for continuous lighting or dusk to dawn lighting of government owned street lighting systems.

The Customer will own, operate, and maintain the street lighting system including lamps and glass replacements but excluding distribution facilities installed by the Company to serve the lighting system.

TIME PERIOD

Dusk:	The time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights.
Dawn:	The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off the lights.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Basic Service Charge	$3.480	per installed lamp
Energy Charge	$0.07613	per kWh

TRIP CHARGE

A $100.00 trip charge per light will be charged when a Customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street lighting equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. Billed energy is based upon the summation of the contracted energy rating of installed facilities specified in the street lighting contract.

2. The Customer's bill will not be reduced due to lamp, photocontrol, cable repair or cable replacement outages.

3. At the request of the Customer, Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost. When the extension is underground, the customer will provide earthwork as specified in the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

    a. Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

4. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

5. In addition, service may be subject to special terms and conditions as provided for in a Customer contract or service agreement.

CONTRACT PERIOD

The contract period for service under this rate schedule will be a fixed period of not less than 1 year and not more than 20 years, as agreed to by the Customer and as specified in the street lighting contract.

AVAILABILITY

This rate schedule is available to eligible City of Phoenix service accounts.

DESCRIPTION

E-67 is a rate that is applicable for the lighting of alleys, buildings, and other public places owned or maintained by the City. Street lighting service is not eligible for this schedule. Service to traffic signals is limited to those installations being served as of January 31, 1985, under the Agreement of April 4, 1930, as modified, between Central Arizona Light and Power Company and the City of Phoenix. No new or reconnected traffic signal installations may be served after that time.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Energy Charge	$0.06493	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. The Customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

5. Direct Access Customers are not eligible for this rate schedule.

AVAILABILITY

This rate schedule is applicable to those portions of cities, towns and unincorporated communities in which the Company does a general retail electric business and where the Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered after December 1, 2021.

DESCRIPTION

E-68 is a rate that is applicable for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of Company's facilities.

TIME PERIOD

Dusk: The time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

CHARGES

The monthly bill will consist of the fixture and energy charges, plus adjustments:

I. FIXTURES (Includes Mounting Arm, if applicable)

Fixture Equipment Class	Fixture Cost Range (per unit)	Investment by Company Monthly Rate	Investment by Others Monthly Rate
A	$ 1 - $ 430	$ 6.77	$ 2.06
B	$ 431 - $ 520	$ 8.25	$ 2.50
C	$ 521 - $ 640	$ 9.90	$ 3.06
D	$ 641 - $ 820	$ 11.83	$ 3.92
E	$ 821 - $ 910	$ 14.98	$ 4.35
F	$ 911 - $ 1,010	$ 16.67	$ 4.82
G	$ 1,011 - $ 1,110	$ 18.23	$ 5.31
H	$ 1,111 - $ 1,250	$ 20.67	$ 5.96
I	$ 1,251 - $ 1,520	$ 23.00	$ 7.24
J	$ 1,521 - $ 1,670	$ 28.04	$ 7.96
K	$ 1,671 - $ 1,850	$ 31.17	$ 8.82

Note: Equipment cost greater than $1,850 shall be Customer owned.

II. ENERGY (Includes Generation, T&D, RCS & SBC)

Monthly energy charges for new lighting fixtures will be determined by the Company using the following method:

kWh = Fixture Wattage x 344 Usage Hours

Generation = kWh per month x $
0.07856

T&D, RCS, System Benefits = kWh per month x $
0.03182

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.

2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the Customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.

3. Listed kWh reflects the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

4. kWh is determined by the company based on the rated wattage of the equipment and an established average hourly usage per month.

5. The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the Customer provides earthwork and conduit (excluding the underground to overhead transition).

III. POLES

				CHARGES	
			Height	Investment by Company	Investment by Others
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$ 15.21	$ 2.08
			22 ft.	$ 17.12	$ 2.34
			25 ft.	$ 18.54	$ 2.54
			30 ft.	$ 21.29	$ 2.91
			32 ft.	$ 22.37	$ 2.95
		2 Simplex Adapters	12 ft.	$ 16.22	$ 2.22
			22 ft.	$ 18.64	$ 2.55
			25 ft.	$ 19.45	$ 2.66
			30 ft.	$ 22.61	$ 3.10
			32 ft.	$ 24.11	$ 3.31
	Square Steel	5"	13 ft.	$ 17.44	$ 2.38
			15 ft.	$ 15.58	$ 2.13
			23 ft.	$ 18.49	$ 2.53
			25 ft.	$ 20.33	$ 2.78
			28 ft.	$ 22.57	$ 3.09
			32 ft.	$ 22.44	$ 3.08
	Concrete		12 ft.	$ 52.03	$ 7.15
	Fiberglass		12 ft.	$ 44.06	$ 6.04
	Decorative Transit	4"	16 ft.	$ 42.95	$ 5.91
	Decorative Transit	6"	30 ft.	$ 82.95	$ 11.41
	Hinged Poles	Square	15 ft.	$ 16.50	$ 1.33
		Round	19 ft.	$ 14.92	$ 1.20
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$ 14.63	$ 1.99
			22 ft.	$ 16.55	$ 2.26
			25 ft.	$ 17.94	$ 2.46
			30 ft.	$ 20.72	$ 2.85
			32 ft.	$ 21.78	$ 2.98
		2 Simplex Adapters	12 ft.	$ 15.63	$ 2.13
			22 ft.	$ 17.47	$ 2.38
			25 ft.	$ 18.86	$ 2.57
			30 ft.	$ 22.02	$ 3.01
			32 ft.	$ 23.52	$ 3.22
		3 Bolt Arm	32 ft.	$ 27.03	$ 3.69
	Square Steel	5"	13 ft.	$ 16.88	$ 2.32
			15 ft.	$ 17.25	$ 2.34
			23 ft.	$ 17.91	$ 2.46
			25 ft.	$ 19.76	$ 2.72
			28 ft.	$ 21.95	$ 3.01
			32 ft.	$ 22.80	$ 3.10

III. POLES (cont.)

				CHARGES	
			Height	Investment by Company	Investment by Others
C. Direct Bury	Round Steel		19 ft.	$ 23.03	$ 3.16
			30 ft.	$ 17.98	$ 3.31
			38 ft.	$ 21.94	$ 3.40
		Self	40 ft.	$ 27.03	$ 4.26
		Stepped	25 ft.	$ 62.21	$ 5.06
			32 ft.	$ 65.52	$ 5.33
			49 ft.	$ 81.34	$ 11.19
	Square Steel	4"	34 ft.	$ 19.84	$ 3.42
		5"	20 ft.	$ 18.84	$ 3.10
			30 ft.	$ 19.64	$ 3.22
			38 ft.	$ 21.31	$ 3.68
		8"	28 ft.	$ 35.59	$ 2.87
			32 ft.	$ 37.20	$ 3.03
	Decorative Transit		41 ft 6"	$ 25.61	$ 3.74
	Decorative Transit		47 ft.	$ 31.91	$ 4.68
	Steel Distribution Pole (for lighting only)		35 ft.	$ 29.45	$ 3.86
D. Post Top	Decorative Transit Anchor Base		16 ft.	$ 43.88	$ 6.01
	Gray Steel/Fiberglass		23 ft.	$ 15.20	$ 2.48
	Black Steel		23 ft.	$ 16.76	$ 2.74
E. Existing distribution pole suitable for streetlight use				$ 1.83	--
F. Wood	Wood Poles		30 ft.	$ 11.20	
			35 ft.	$ 11.20	
			40 ft.	$ 16.00	

IV. ANCHOR BASE

			CHARGES	
		Height	Investment by Company	Investment by Others
A. Flush		4 ft.	$ 12.38	$ 1.69
		6 ft.	$ 14.78	$ 2.54
B. Pedestal		8 ft.	$ 16.93	$ 2.93
	For 32' Round Steel Pole only	4 ft. 6"	$ 11.74	$ 2.01

V. CHARGES FOR OPTIONAL OR ADDITIONAL COMPANY OWNED EQUIPMENT

Underground Circuit Charges	
a. Per foot of cable, installed under paving	$ 0.19757
b. Per foot of cable, not installed under paving	$ 0.06973

TRIP CHARGE

A $150.00 trip charge per light will be charged when a Customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street lighting equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Standard charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.

5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.

2. The Customer's bill will not be reduced due to photocontrol or cable repair or replacement outages.

3. Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

4. The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the Customer. When the extension is underground, the customer will provide earthwork as specified in the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

    a. Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

5. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill. In addition, service may be subject to special terms and conditions as provided for in a Customer contract, maintenance, or service agreement.

AVAILABILITY

This rate schedule is available to Customers that pump water for agricultural irrigation or municipal water service.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge, and an energy charge. Rate Schedule E-221 is a special rate for Customers pumping irrigation water or for water utilities pumping potable water to service the citizens of a city, town, or unincorporated community.

CHARGES

The monthly bill will consist of the following charges or a minimum bill, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
Self-Contained Meter	$ 1.389	per day
Instrument Rated Meter	$ 2.418	per day
Primary Meter	$ 5.925	per day

Demand Charge	$ 5.232	per kW

Energy Charge for the first 240 kWh	$ 0.13391	per kWh
Energy Charge for all additional kWh	$ 0.09244	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 per day plus $ 5.232 per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or

2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603	per day
Billing	$ 0.035	per day
Meter Reading	$ 0.011	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740	per day
Instrument Rate Meter	$ 1.769	per day
Primary Meter	$ 5.276	per day

Demand Charge Components		
Generation	$ 1.248	per kW
Delivery	$ 1.114	per kW
Transmission	$ 2.870	per kW

Energy Charge Components		
Generation for the first 240 kWh	$ 0.09626	per kWh
Generation for all additional kWh	$ 0.07670	per kWh
Delivery for the first 240 kWh	$ 0.03378	per kWh
Delivery for all additional kWh	$ 0.01187	per kWh
System Benefits (all kWh)	$ 0.00387	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown below.

4. Electric service is supplied at a single point of delivery and measured through a single meter. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.

AVAILABILITY

This rate schedule is available to Standard Offer Customers for service to water pumps for the purpose of agricultural irrigation.

DESCRIPTION

Rate Schedule E-221 AG is a rate schedule for agricultural Customers using a pump to move water for agricultural irrigation. This rate has three parts: a basic service charge, a demand charge, and an energy charge.

CHARGES

The monthly bill will consist of the following charges or a minimum bill, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
Self-Contained Meter	$ 1.389	per day
Instrument Rated Meter	$ 2.418	per day
Primary Meter	$ 5.925	per day

Demand Charge	$ 4.769	per kW

Energy Charge for the first 240 kWh	$ 0.11988	per kWh
Energy Charge for all additional kWh	$ 0.08751	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 per day plus $ 4.769 per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or

2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603	per day
Billing	$ 0.035	per day
Meter Reading	$ 0.011	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740	per day
Instrument Rate Meter	$ 1.769	per day
Primary Meter	$ 5.276	per day

Demand Charge Components		
Generation	$ 1.248	per kW
Delivery	$ 0.651	per kW
Transmission	$ 2.870	per kW

Energy Charge Components		
Generation for the first 240 kWh	$ 0.09626	per kWh
Generation for all additional kWh	$ 0.07669	per kWh
Delivery for the first 240 kWh	$ 0.01975	per kWh
Delivery for all additional kWh	$ 0.00695	per kWh
System Benefits (all kWh)	$ 0.00387	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements, the Customer will pay the cost to install and remove the equipment.

If the load does not meet the power factor requirements, the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

DEFINITIONS

1. The term Agricultural is defined as the practice of farming, including the cultivation of soil for the production of crops.

2. The term Irrigation is defined as the watering of land by artificial means to foster plant growth.

3. The term Pump is defined as the mechanical device using suction or pressure to raise or move water.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. This schedule is not applicable to breakdown, standby, supplemental, residential, or resale service.

5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.

6. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

7. Direct Access Customers are not eligible for this rate schedule.

8. This rate schedule is not available to service for which rate schedules E-34 or E-35 is applicable.

AVAILABILITY

This rate schedule is available to Standard Offer Customers for service to a water pump for the purpose of Agricultural Irrigation.

DESCRIPTION

Rate Schedule E-221 AG TOU is a rate schedule for Agricultural Customers using a pump to move water for Agricultural Irrigation. This rate has three parts: a basic service charge, a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by both season (summer or winter) and the time of day that the energy is used (On-Peak, Off-Peak, or Super Off-peak).

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Super Off Peak:	10:00 am – 3:00 pm (Winter only)
Summer months:	May through October billing cycle
Winter months:	November through April billing cycle

CHARGES

The monthly bill will consist of the following charges or a minimum bill, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
Self-Contained Meter	$ 1.389	per day
Instrument Rated Meter	$ 2.418	per day
Primary Meter	$ 5.925	per day

Demand Charge – On-Peak	$ 5.018	per kW

	Summer	Winter	
Energy Charge On-Peak	$ 0.12804	$ 0.12804	per kWh
Energy Charge Off-Peak	$ 0.08786	$ 0.08786	per kWh
Energy Charge Super Off-Peak		$ 0.04038	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 per day plus $ 5.018 per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or

2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603	per day
Billing	$ 0.035	per day
Meter Reading	$ 0.011	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740	per day
Instrument Rate Meter	$ 1.769	per day
Primary Meter	$ 5.276	per day

Demand Charge Components	On-Peak	
Generation	$ 1.276	per kW
Delivery	$ 0.872	per kW
Transmission	$ 2.870	per kW

Energy Charge Components	Summer	Winter	
Generation Charge On-Peak	$ 0.10294	$ 0.10294	per kWh
Generation Charge Off-peak	$ 0.06276	$ 0.06276	per kWh
Generation Charge Super Off-peak		$ 0.02259	per kWh
Delivery Charge On-Peak	$ 0.02123	$ 0.02123	per kWh
Delivery Charge Off-peak	$ 0.02123	$ 0.02123	per kWh
Delivery Charge Super Off-peak		$ 0.01392	per kWh
System Benefits (all kWh)	$ 0.00387	$ 0.00387	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

DEFINITIONS

1. The term Agricultural is defined as the practice of farming, including the cultivation of soil for the production of crops.

2. The term Irrigation is defined as the watering of land by artificial means to foster plant growth.

3. The term Pump is defined as the mechanical device using suction or pressure to raise or move water.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.

6. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

7. Direct Access Customers are not eligible for this rate schedule.

8. This rate schedule is not available to service for which rate schedules E-34 or E-35 is applicable.

AVAILABILITY

This rate schedule is available to Customers that pump water for agricultural irrigation, or municipal water service.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge, and an energy charge. Both the demand and energy charge vary depending on the time-of-day energy is used. Rate Schedule E-221-8T is a special rate for Customers pumping agricultural irrigation water or for water utilities pumping potable water to service the citizens of a city, town, or unincorporated community.

TIME PERIODS

On-Peak hours:	11:00 a.m. - 9:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

CHARGES

The monthly bill will consist of the following charges, or a minimum bill as discussed below, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge		
Self-Contained Meter	$ 1.389	per day
Instrument Rated Meter	$ 2.418	per day
Primary Meter	$ 5.925	per day

Demand Charge On-Peak	$ 7.572	per kW
Demand Charge Off-Peak	$ 5.534	per kW

Energy Charge On-Peak	$ 0.11287	per kWh
Energy Charge Off-Peak	$ 0.06070	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 per day plus $ 7.572 per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or
2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603	per day
Billing	$ 0.035	per day
Meter Reading	$ 0.011	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740	per day
Instrument Rate Meter	$ 1.769	per day
Primary Meter	$ 5.276	per day

Demand Charge Components		
Generation on-peak	$ 2.769	per kW
Generation off-peak	$ 3.601	per kW
Delivery on-peak	$ 1.933	per kW
Delivery off-peak	$ 1.933	per kW
Transmission on-peak	$ 2.870	per kW

Energy Charge Components		
Generation on-peak	$ 0.10682	per kWh
Generation off-peak	$ 0.05465	per kWh
Delivery (all kWh)	$ 0.00218	per kWh
System Benefits (all kWh)	$ 0.00387	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown below.

5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.

RATE SCHEDULE GS-SCHOOLS L
GENERAL SERVICE TIME OF USE (401 kW +)
ELEMENTARY AND SECONDARY SCHOOLS

AVAILABILITY

This rate schedule is available to private and public elementary and secondary schools (K-12) whose average monthly maximum demand is greater than 400 kW and less than 3,000 kW per month.

DESCRIPTION

This rate schedule is specifically for K-12 educational facilities and is available only to the actual meter of the school that is connected to classrooms or facilities directly related to teaching. The rate does not apply to separate facilities such as administration offices, or bus depots. This rate schedule is a three-part rate: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule GS-SCHOOLS M or GS-SCHOOLS L based on the average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer:	May through October billing cycles
Winter:	November through April billing cycles

Summer Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

Winter Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Rates

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 3.698	per day
For service through Instrument-Rated Meters	$ 4.738	per day
For service at Primary Voltage	$ 8.275	per day
For service at Transmission Voltage	$ 46.760	per day

Demand Charges			
Secondary Service	First 100 kW	$ 13.376	per kW
	All additional kW	$ 7.452	per kW
Primary Service	First 100 kW	$ 12.457	per kW
	All additional kW	$ 6.538	per kW
Transmission Service	First 100 kW	$ 9.873	per kW
	All additional kW	$ 3.946	per kW

Energy Charges			
	Summer Peak	Winter	
On-Peak	$ 0.20238	$ 0.13543	per kWh
Off-Peak	$ 0.08281	$ 0.05540	per kWh

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule will be based on the maximum demand kW used during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts	$ 2.905	per day
Billing	$ 0.037	per day
Meter Reading	$ 0.011	per day
Meter Charge (only one applies)		
Self-Contained Meter	$ 0.745	per day
Instrument-Rated Meter	$ 1.785	per day
Primary Voltage Meter	$ 5.322	per day
Transmission Voltage Meter	$ 43.807	per day

Demand Charge Components
(only one service voltage applies in addition to the Transmission and Ancillary charge)

Transmission & Ancillary		$ 2.870	per kW
Delivery - Secondary Service	First 100 kW	$ 10.506	per kW
	All additional kW	$ 4.582	per kW
Delivery - Primary Service	First 100 kW	$ 9.587	per kW
	All additional kW	$ 3.668	per kW
Delivery - Transmission Service	First 100 kW	$ 7.003	per kW
	All additional kW	$ 1.076	per kW

Energy Charge Components

	Summer Peak	Winter	
Generation On-Peak	$ 0.18021	$ 0.11326	per kWh
Generation Off-Peak	$ 0.06064	$ 0.03323	per kWh

Delivery	$ 0.01830	per kWh
System Benefits	$ 0.00387	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

5. Direct Access Customers are not eligible for this rate schedule.

6. Service under this schedule is generally provided at secondary voltage; primary voltage when the Customer owns the distribution transformer(s); or transmission voltage.

RATE SCHEDULE GS-SCHOOLS M
GENERAL SERVICE TIME-OF-USE (0 kW – 400 kW)
ELEMENTARY AND SECONDARY SCHOOLS

AVAILABILITY

This rate schedule is available to private and public elementary and secondary schools (K-12) whose average monthly maximum demand is less than or equal to 400 kW per month.

DESCRIPTION

This rate schedule is specifically for K-12 educational facilities and is available only to the actual meter of the school that is connected to classrooms or facilities directly related to teaching. The rate does not apply to separate facilities such as administration offices, or bus depots. This rate schedule has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule GS-SCHOOLS M or GS-SCHOOLS L based on the average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer:	May through October billing cycles
Winter:	November through April Billing Cycles

Summer Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

Winter Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Rates

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 1.393	per day
For service through Instrument-Rated Meters	$ 2.424	per day
For service at Primary Voltage	$ 5.937	per day
For service at Transmission Voltage	$ 44.158	per day

Demand Charges			
Secondary Service	First 100 kW	$ 13.606	per kW
	All additional kW	$ 7.589	per kW
Primary Service	First 100 kW	$ 12.679	per kW
	All additional kW	$ 6.660	per kW
Transmission Service	First 100 kW	$ 10.050	per kW
	All additional kW	$ 4.033	per kW

Energy Charges:			
	Summer Peak	Winter	
On-Peak	$ 0.22343	$ 0.14956	per kWh
Off-Peak	$ 0.08360	$ 0.05597	per kWh

For billing purposes, including determination of monthly maximum demands, the kW used in this rate schedule shall be based on the maximum demand kW used during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the month.

Unbundled Components of the Bundled Charges

Bundled charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts	$ 0.605	per day
Billing	$ 0.036	per day
Meter Reading	$ 0.011	per day

Meter Charge (only one applies)		
Self-Contained Meter	$ 0.741	per day
Instrument-Rated Meter	$ 1.772	per day
Primary Voltage Meter	$ 5.285	per day
Transmission Voltage Meter	$ 43.506	per day

Demand Charge Components
(only one service voltage applies in addition to the Transmission and Ancillary charge)

Transmission & Ancillary		$ 2.870	per kW
Delivery - Secondary Service	First 100 kW	$ 10.736	per kW
	All additional kW	$ 4.719	per kW
Delivery - Primary Service	First 100 kW	$ 9.809	per kW
	All additional kW	$ 3.790	per kW
Delivery - Transmission Service	First 100 kW	$ 7.180	per kW
	All additional kW	$ 1.163	per kW

Energy Charge Components

	Summer Peak	Winter	
Generation On-Peak	$ 0.19205	$ 0.11818	per kWh
Generation Off-Peak	$ 0.05222	$ 0.02459	per kWh

Delivery	$ 0.02751	per kWh
System Benefits	$ 0.00387	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers are not eligible for this rate schedule.

5. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

6. Service under this schedule is generally provided at secondary voltage; primary voltage when the Customer owns the distribution transformer(s); or transmission voltage.

AVAILABILITY

The Demand Side Management Adjustment Charge (DSMAC) applies to all Customer service accounts.

DESCRIPTION

The monthly DSMAC charge is used to recover the cost of Commission-approved programs and services to meet compliance with Arizona's Energy Efficiency Standard and lost fixed costs associated with energy efficiency programs and renewable programs that are not collected through base rates.

CHARGES

The monthly charge for each service account will be calculated at the following rate:

For all Residential Customers:		
All kWh	$0.XXXXXXX	per kWh

For General Service Customers not billed a demand charge:		
All kWh	$0.XXXXXX	per kWh

For General Service Customers billed a demand charge:		
All billed kW or billed on-peak kW for TOU customers	$0.XXX	per kW

SERVICE DETAILS

1. The DSMAC is calculated annually and will go into effect upon approval of the Company's annual DSM Implementation Plan and will remain in effect for the following 12-month period unless otherwise ordered by the Commission.

2. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

3. Charges under Adjustment Schedules REAC-1 and DSMAC-1 may be combined and shown on the "Environmental Benefits Surcharge" line of the Customer's monthly bill.

This adjustor is no longer applicable to any rate structure and is cancelled as of XXXX in Decision No. XXXXX.

This adjustor is no longer applicable to any rate structure and is cancelled as of XXXX in Decision No. XXXXX.

ADJUSTMENT SCHEDULE PSA-1
POWER SUPPLY ADJUSTMENT

AVAILABILITY

The Power Supply Adjustment (PSA) applies to all Customer bills with the exception of E-36 XL, AG-X, and Direct Access service.

DESCRIPTION

This adjustment schedule recovers or credits Customer bills for any fuel and purchased power costs that vary from the cost of fuel collected in base rates.

CHARGES

PSA Historical Component	$0.XXXXXX	per kWh
PSA Forward Component	$0.XXXXXX	per kWh
PSA Transition Component	$0.000000	per kWh

SERVICE DETAILS

1. The PSA Historical Component, PSA Forward Component, and PSA Transition Component are defined in the Company's Power Supply Adjustment Plan of Administration.

2. This adjustment is recalculated on an annual basis, except for the Transition Component which may apply from time to time, and will go into effect with the first billing cycle in February (without proration) and will remain in effect for a 12-month period unless otherwise ordered by the Commission.

3. All terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

ADJUSTMENT SCHEDULE RCDAC-1
RETURNING CUSTOMER DIRECT ACCESS CHARGE

AVAILABILITY

The Returning Customers Direct Access Charge (RCDAC) will apply to Customers, or an aggregated group of Customers, of 3 MW or greater who left Standard Offer or special contract service for competitive generation suppliers and are returning to Standard Offer service.

CHARGES

The RCDAC will be identified in the Electric Service Agreement between the Customer and the Company and will be in addition to any Standard Offer service charges. The charge will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning Customer. The costs associated with serving Customers that are required to enter into RCDAC agreements will be separate from the retail power supply costs subject to recovery through the Power Supply Adjustment.

Types of costs that will be used to develop the RCDAC are incremental Power Supply, Transmission, Ancillary Services and Metering costs as defined in the Returning Customer Direct Access Charge Plan for Administration. These costs will be amortized over an appropriate period to allow for timely recovery. The RCDAC will not be billed longer than 12 months for any individual Customer.

SERVICE DETAILS

1. Customers that have been Direct Access Customers since beginning service from the Company are considered returning Customers for the purposes of this schedule.

2. The RCDAC will only be applied if the Customer wants to return to Standard Offer service and the Company did not include that Customer load in planned resource acquisitions. If the Company is provided one year's advance notice of the Customer's intent to return to Standard Offer service, that Customer will not be assessed the RCDAC charge.

3. APS may create a specific RCDAC in each individual case and require the Customer to enter into a service agreement that specifies the charge, its duration, and how it will be applied and collected. In situations where an aggregated group of Customers wish to return to Standard Offer service, each Customer from the group will be charged the same rate for the same duration and an Electric Service Agreement will be required from each customer.

4. All provisions of the Customer's current applicable rate schedule will apply in addition to this charge.

ADJUSTMENT SCHEDULE REAC-1
RENEWABLE ENERGY ADJUSTMENT CHARGE

AVAILABILITY

The Renewable Energy Adjustment Charge (REAC) applies to all Customer service accounts.

DESCRIPTION

The monthly REAC charge recovers expenditures made by the Company to meet compliance with Arizona's Renewable Energy Standard.

CHARGES

The monthly charge for each service account will be calculated at the following rates and surcharge caps:

kWh Charge	$X.XXXXXX	per kWh

Surcharge Caps (per service account per month)

Residential Customers	$XX.XX	per Month
Non-Residential Customers		
Extra-Small and Small	$ XX.XX	per Month
Medium	$ XX.XX	per Month
Large	$ XX.XX	per Month
Extra-Large	$ XX.XX	per Month

Surcharge caps shown above apply to the following:

1. Customers who have not installed an on-site renewable distribution generation system;

2. Customers that installed an on-site renewable distribution generation system prior to July 1, 2012; and

3. Customers that installed an on-site renewable distribution generation system after July 1, 2012 and before February 1, 2013 and did not receive an incentive.

Alternative REAC Charges, Flat Charges, and Minimum Charges

Residential Customers	$ XX.XX	Flat charge per Month
Non-Residential Customers		
Extra-Small	$ XX.XX	Minimum charge per Month
	$ XX.XX	Surcharge cap
Small	$ XX.XX	Minimum charge per Month
	$ XX.XX	Surcharge cap
Medium	$ XX.XX	Flat charge per Month
Large	$ XX.XX	Flat charge per Month
Extra-Large	$ XX.XX	Flat charge per Month

Flat charges shown above apply to the following:

1. Customers that installed a renewable distributed generation system after July 1, 2012 and received an incentive; and

2. Customers that installed a renewable distributed generation system interconnected to the Company's distribution grid after February 1, 2013, regardless of whether an incentive was received.

Minimum Charges and Surcharge Caps shown above apply to the following:

1. Extra-Small and Small General Service Customers that installed a renewable distributed generation system after July 1, 2012 and received an incentive; and

2. Extra-Small and Small General Service Customers that installed a renewable distributed generation system and interconnected to the Company's distribution grid after February 1, 2013, regardless of whether an incentive was received.

NON-RESIDENTIAL CUSTOMER BILLING CATEGORIES

Non-residential Customers served under the following retail rate schedules will be billed under the surcharge categories shown below:

Retail Rate Schedule	Surcharge Category
E-30, E-32 XS, E-32 XS D, E-32TOU XS, E-45, E-47, E-58, E-59, E-67, E-68, Contract 12	Extra-Small
E-32 S, E-32TOU S	Small
E-32 M, E-32TOU M	Medium
E-32 L, E-32TOU L, E-32 L SP, GS-Schools L	Large
E-34, E-35, XHLF, E-36 XL	Extra-Large

For non-residential Customers served under the following rate schedules, the surcharge category will be based on the monthly billing demand as shown below:

Retail Rate Schedule	Monthly Billing Demand	Surcharge Category
E-221, E-221 8T, E-221 AG, E-221 AG TOU, GS-Schools M, E-20	20 kW and less	Extra-Small
E-221, E-221 8T, E-221 AG, E-221 AG TOU, GS-Schools M	21 - 100 kW	Small
E-221, E-221 8T, E-221 AG, E-221 AG TOU	101- 400 kW	Medium
E-221, E-221 8T, E-221 AG, E-221 AG TOU	> 400 kW	Large
GS-Schools M	> 100 kW	Medium
E-20	> 20 kW	Small

SERVICE DETAILS

1. The charges will be revised annually, effective on the first billing cycle in January, or as otherwise ordered by the Arizona Corporation Commission, and will not be prorated.

2. All the terms and charges in the customer's rate schedule continue to apply to electric service provided under this adjustment.

3. Charges applied under Adjustment Schedules REAC-1 and DSMAC-1 may be combined and shown on the "Environmental Benefits Surcharge" line of the Customer's monthly bill.

AVAILABILITY

The Self-Directed Renewable Resources (SDR) Adjustment Schedule is available to all Customers who meet the eligibility requirements below.

DESCRIPTION

The SDR is a self-direct option available to Customers that meet the eligibility requirements below. Under the SDR adjustment schedule, Customers may reserve their REAC-1 contributions, less administrative costs, for exclusive use to help fund qualifying renewable projects at the Customer's site.

ELIGIBILITY REQUIREMENTS

1. Funding Eligibility:

    a. The Customer is eligible to receive funds pursuant to this schedule if the total of all REAC related payments made to the Company for the customer's service account or accounts, individually or collectively, total $25,000 or more in any one calendar year (January – December).

    b. Funds collected from the Customer in any one year (the Payment Year) will be available to the Customer for self-directed projects in the following year (the Funding Year). Funds received during the Funding Year will not exceed payments collected by the Company in the Payment Year. In addition, if the Customer has facilities in multiple service territories, only those payments collected by the Company are eligible for SDR funding.

    c. Customers requesting funds for self-directed projects must declare their intention by applying in writing to the Company on or before March 31 of the Payment Year. The application must include a description of the proposed project and its expected cost.

    d. The Customer shall provide at least half of the funds necessary to complete the proposed project, as required by A.A.C. R14-2-1809.B.

2. Project Eligibility:

    a. SDR funds obtained by the Customer from the Company may only be used for projects physically located within the Company's service territory.

b. Projects specified in the Company's Distributed Energy Administration Plan ("DEAP") are eligible for SDR funding. SDR Customers must request incentives no greater than the prescribed incentives specified in the DEAP. If the Customer wishes to apply funds to a project not specified in the DEAP, the Customer must submit documentation detailing project economics and funding requirements.

c. Any project proposed by the Customer must meet the requirements for a Distributed Renewable Energy Resource described in the Arizona Corporation Commission's Renewable Energy Standard Tariff Rules (A.A.C. R14-2-1802.B).

d. For purposes of financing SDR projects, funds provided by the Company may be assigned to third parties. Such assignment will be at the Customer's sole discretion. The Company assumes no liability for third-party assigned funds.

SERVICE DETAILS

1. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

2. All Renewable Energy Credits derived from any project funded through this schedule, including generation and Extra Credit Multipliers, will be applied to satisfy the Company's annual Renewable Energy Standard requirements.

ADJUSTMENT SCHEDULE TCA-1
TRANSMISSION COST ADJUSTMENT

AVAILABILITY

The Transmission Cost Adjustment (TCA) charge applies to all Customer monthly bills.

DESCRIPTION

The TCA allows the Company to recover transmission costs associated with service to retail Customers at the level approved by the Federal Energy Regulatory Commission (FERC) as new transmission rates become effective.

CHARGES

Customer Class	TCA Charge	
Residential	$0.XXXXXX	per kWh
General Service 20 kW or less	$0.XXXXXX	per kWh
General Service over 20 kW, under 3,000 kW	$0.XXX	per kW
General Service 3,000 kW and over	$0.XXX	per kW

SERVICE DETAILS

1. The TCA will be calculated annually and will go into effect with the first billing cycle in June (without proration) and will remain in effect for the following 12-month period unless otherwise ordered by the Commission.

2. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

ADJUSTMENT SCHEDULE TEAM
TAX EXPENSE ADJUSTOR MECHANISM

APPLICATION

The Tax Expense Adjustor Mechanism (TEAM) will be applied to all Customer monthly bills.

DESCRIPTION

The TEAM allows the Company to pass through to its Customers any income tax effects that materially impact the Company's annual revenue requirements as a result of federal or state income tax legislation.

CHARGES

The charge will be calculated at the following rate:

TEAM Phase I Component	($0.000000)	per kWh
TEAM Phase II Component	$0.000000	per kWh
TEAM Phase III Component	($0.000000)	per kWh

SERVICE DETAILS

1. The TEAM Phase I Component, TEAM Phase II Component, and TEAM Phase III Component are defined in the Company's Tax Expense Adjustment Mechanism Plan of Administration.

2. The TEAM Adjustment Charge will be calculated annually and will go into effect with the first billing cycle in January (without proration) and will remain in effect for the following 12-month period unless otherwise stipulated or ordered by the Commission. The rates calculated from impacts associated with Phase I, Phase II and Phase III will be included on customer bills as a single line item in accordance with the Plan of Administration.

3. AG-X customers will receive 75.64% of the Adjustment Charge, and customers taking service under rate schedules HLF-1, HLF-2, and HLF-3 will receive 86.84% of the Adjustment Charge.

4. All terms and conditions in the Customer's rate schedule continue to apply to electric service provided under this adjustment schedule.

AVAILABILITY

All residential Customers who can reduce the amount of energy used when called upon may volunteer to participate in this rate rider. The Customer must meet the requirements listed in the service details below.

DESCRIPTION

Critical Peak Pricing (CPP) events are specific hours within the summer months when the Company is expecting extreme temperatures, high energy (kWh) usage, high market energy costs, or is experiencing a major generation or transmission outage. Customers on this rate rider agree to use less energy during these CPP events. Energy charges during CPP events are higher than the remainder of the summer On-Peak hours, but the Customer also receives a discount for all energy used during the CPP summer months.

CHARGES

The following charge will be in addition to the On-Peak charge in the Customer's rate schedule:

Charge for energy use during Critical Peak hours	$0.25000	per kWh

The following discount will apply to all non-Critical Peak hours during CPP summer months (June through September):

Energy Discount for summer non-Critical Peak hours	($0.012143)	per kWh

SERVICE DETAILS

1. This rate rider requires the Customer to have a standard AMI meter in place.

2. A Customer cannot be on this CPP rate rider and another demand response program offered by the Company. Customers may participate in this rate rider and the legacy net metering rate rider, but any exported generation during a CPP event will not be applied toward hours in another CPP event.

3. Details of a CPP event are as follows:

a. CPP events will only be scheduled from 3 p.m. to 8 p.m., Monday through Friday in the months of June through September. CPP events will not be scheduled on holidays (Independence Day on July 4th and Labor Day on the first Monday in September).

b. At least 6 and no more than 18 CPP events may be called per calendar year, and each event will last for a period of five hours.

c. Customers will be notified of a CPP event in advance. By 4:00 PM the day prior to the event, the Customer will receive a phone message, e-mail, or text message. The Customer is responsible to watch for this message.

d. Once noticed, a CPP event will not be cancelled.

4. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

RATE RIDER E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Energy Support Program.

DESCRIPTION

The Energy Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the Federal Poverty guidelines or those receiving assistance from an APS approved limited income assistance program.

DISCOUNT

The following discount will apply to the Customer's bill, subject to the service details below:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%	60%	$165	per bill
Greater than 75% up to and including 200%	25%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

4. Customers may not receive discounts under both this rider and Rate Rider E-4 at the same time.

5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER LEGACY E-3
RESIDENTIAL ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the solar grandfathering program and meet the requirements of the Energy Support Program.

DESCRIPTION

The Energy Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program.

Eligibility for this rate rider will be frozen on September 1, 2017. This means no new Customers will be served under this rider on or after that date, and any Customer that discontinues participation in the Energy Support Program or the solar grandfathering program cannot return to this rider at a later date.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider.

FROZEN

RATES

The following discounts will apply to the Customer's bill, subject to the service details below:

For bills with total energy usage of:		
0 kWh to 400 kWh	65% discount	per bill
401 kWh to 800 kWh	45% discount	per bill
801 kWh to 1200 kWh	26% discount	per bill
1201 kWh and above	$31.75	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. Customers may not receive discounts under both this rider and Rate Rider Legacy E-4 at the same time.

3. Customers who leave the grandfathering program are no longer eligible for Rate Rider Legacy E-3 but may be served under Rate Rider E-3 if the Customer continues to qualify.

4. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

FROZEN

RATE RIDER E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Medical Care Equipment Support Program.

DESCRIPTION

The Medical Care Equipment Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program and who require qualifying life-sustaining medical equipment.

DISCOUNT

The following discount will apply to energy purchased under this rate rider:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%	60%	$165	per bill
Greater than 75% up to and including 200%	35%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

4. Customers may not receive discounts under both this rider and Rate Rider E-3 at the same time.

5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER LEGACY E-4
RESIDENTIAL MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the solar grandfathering program and meet the requirements of the Medical Care Equipment Support Program.

DESCRIPTION

The Medical Care Equipment Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program and who require qualifying life-sustaining medical equipment.

Eligibility for this rate rider will be frozen on September 1, 2017. This means no new Customers will be served under this rider on or after that date, and any Customer that discontinues participation in the Medical Care Equipment Support Program or the solar grandfathering program cannot return to this rider at a later date.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider.

FROZEN

RATES

The following discounts will apply to the Customer's bill, subject to the service details below:

For bills with total energy usage of:		
0 kWh to 800 kWh	65% discount	per bill
801 kWh to 1400 kWh	45% discount	per bill
1401 kWh to 2000 kWh	26% discount	per bill
2001 kWh and above	$60.00	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. Customers may not receive discounts under both this rider and Rate Rider Legacy E-3 at the same time.

3. Customers who leave the grandfathering program are no longer eligible for Rate Rider Legacy E-4 but may be served under Rate Rider E-4 if the Customer continues to qualify.

4. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

FROZEN

RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

AVAILABILITY

This rate rider is available to Customers that qualify for the residential solar grandfathering program. It may be used in conjunction with the residential Legacy rate schedules for distributed generation systems.

This rate rider is frozen effective September 1, 2017. This means a residential Customer that is already taking service under this rate rider before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider. Instead, the residential Customer will be served under an applicable retail rate of their choice and Rate Rider RCP, or a subsequent replacement rider.

FROZEN

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program. A partial requirements Customer has on-site generation that serves some of their electrical requirements and relies on the Company for additional electrical services. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods, i.e. on-peak export energy will be netted against on-peak energy from the Company and vice-versa, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December billing cycle, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

BILLING DETAILS

1. All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for the remaining export energy at the purchase price.

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and otherwise qualify for this rate rider may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application, and otherwise qualify for this rate rider, may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

FROZEN

3. The grandfathering period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternate grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

FROZEN

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection or purchase agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

    a. Provides part of the Customer's energy requirements at the site where the system is installed;

b. Uses renewable resources, as defined by the Arizona Corporation Commission, to generate energy; and

c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

FROZEN

RATE RIDER LEGACY LFCR DG
LEGACY ADJUSTMENT FOR DISTRIBUTED GENERATION

AVAILABILITY

This rate rider is applied to Customers that qualify for the residential solar grandfathering program and interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014. The Legacy LFCR DG Rate Rider does not apply to residential Customers on Rate Schedules Legacy ECT-1R or Legacy ECT-2.

This rate rider is frozen beginning on September 1, 2017. This means no new Customers will be served under this rider on or after that date. This rider will apply to eligible Customers through the 20-year period from the date their solar generator was interconnected to the Company's distribution grid. Charges shown on this schedule may change.

DESCRIPTION

This rate rider recovers a portion of the lost fixed cost revenue that results from the net metering of on-site distributed generation from certain Customers on Net Metering Rate Rider Legacy EPR-6.

CHARGES

The following charges will be applied to the monthly bill in addition to the charges in the Customer's rate schedule:

LFCR DG Charge	$0.700	per kW-DC of generation
Generators not registered with APS	$3.000	per kW-DC of generation

FROZEN

SERVICE DETAILS

1. Monthly charges will be applied to the nameplate kW-DC power rating of the on-site distributed generation system.

2. Any Customer that does not register an on-site distributed generation system with APS through the application and interconnection process when that distributed generation system was installed will be charged the Generators not registered with APS charge.

3. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

RATE RIDER GPS-1
GREEN POWER BLOCK SCHEDULE

AVAILABILITY

This rate rider is available to any Customer who wants to purchase energy specifically generated from renewable resources.

DESCRIPTION

This rate rider allows a Customer to purchase a specific amount of energy (kWh) from the Company that has been generated by a renewable resource. This energy is known as Green Power, and may be generated from any resource designated by the Arizona Corporation Commission as renewable.

Purchases under this rate rider are for 100 kWh blocks of Green Power per month.

CHARGES

The following charge will apply to energy purchased under this rate rider in addition to the charges in the Customer's rate schedule:

Energy Charge	$1.02	per block of 100 kWh

SERVICE DETAILS

1. Green Power may be generated from Company-owned renewable resources, or from a renewable resource that the Company has purchased energy from, and is delivered through the Company's distribution grid.

2. Customers subscribe to a specific number of blocks of renewable energy, each of which equal 100 kWh per block. Participation in this rate rider is limited to the Green Power available. The Company may also limit the amount of energy purchased by a single Customer to 5% of the total Green Power available.

3. Customers must subscribe to the desired number of energy blocks for a minimum of one year. If the charge for each block of energy increases during the subscription year, Customers may cancel participation in this rate rider.

4. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

5. Customers cannot take service under more than one Green Power rate rider at the same time.

AVAILABILITY

This rate rider is available to any Customer who wants to purchase energy specifically generated from renewable resources.

DESCRIPTION

This rate rider allows a Customer to purchase a specific amount of energy (kWh) from the Company that has been generated by a renewable resource. This energy is known as Green Power, and may be generated from any resource designated by the Arizona Corporation Commission as renewable.

Purchases of Green Power under this rate rider are for a percentage of total monthly kWh.

CHARGES

The Customer may choose one of the following options under this rate rider in addition to the charges in the Customer's rate schedule:

Option 1: 100% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0102	per kWh

Option 2: 50% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0051	per kWh

Option 3: 35% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0036	per kWh

Option 4: 10% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0010	per kWh

SERVICE DETAILS

1. Green Power may be generated from Company-owned renewable resources, or from a renewable resource that the Company has purchased energy from, and is delivered through the Company's distribution grid.

2. Participation in this rate rider is limited to the Green Power available. The Company may also limit the amount of energy purchased by a single Customer to 5% of the total Green Power available.

3. Customers must subscribe to the desired percentage of energy usage for a minimum of one year. If the energy charge increases during the subscription year, Customers may cancel participation in this rate rider.

4. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

5. Customers cannot take service under more than one Green Power rate rider at the same time.

RATE RIDER GPS-3
GREEN POWER BLOCK SCHEDULE FOR SPECIAL EVENTS

AVAILABILITY

This rate rider is available to any Customer who wants to purchase energy specifically generated from renewable resources.

DESCRIPTION

This rate rider allows a Customer to purchase a specific amount of energy (kWh) from the Company that has been generated by a renewable resource. This energy is known as Green Power, and may be generated from any resource designated by the Arizona Corporation Commission as renewable.

Purchases under this rate rider are for 100 kWh blocks of Green Power during a temporary special event such as concerts, sporting events, and festivals. Minimum purchase shall be $500.00 per transaction.

CHARGES

The following charge will apply to energy purchased under this rate rider in addition to the charges in the Customer's rate schedule:

Energy Charge	$1.02	per block of 100 kWh

This charge will apply for the duration of the special event as requested by the Customer.

SERVICE DETAILS

1. Green Power may be generated from Company-owned renewable resources, or from a renewable resource that the Company has purchased energy from, and is delivered through the Company's distribution grid.

2. Customers request a specific number of blocks of renewable energy, each of which equal 100 kWh per block, to be used during the special event. Participation in this rate rider is limited to the Green Power available. The Company may also limit the amount of energy purchased by a single Customer to 5% of the total Green Power available.

3. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

4. Customers cannot take service under more than one Green Power rate rider at the same time.

RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR NEW ON-SITE SOLAR DISTRIBUTED GENERATION RESOURCE COMPARISON PROXY EXPORT RATE

AVAILABILITY

This rate rider is available to partial requirements residential Customers with qualified on-site solar generation, served under an applicable residential rate. This rate rider may not be used in conjunction with a grandfathered residential Legacy rate schedule or Legacy rate rider.

DESCRIPTION

A residential Customer with solar generation exports power to the grid from time to time when their generation exceeds the load in their home. The Company will meter this export power on an instantaneous basis and provide a monthly bill credit based on the purchase rate in this schedule.

The purchase rates will be determined as follows:

a. An RCP rate will be determined for each annual tranche of new DG Customers, effective September 1 each year or as determined by the Commission without proration. The RCP rate may not be reduced by more than 10% each year.

b. Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before September 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

c. Each Customer's initial RCP rate will be applicable for 10 years from the time of their interconnection.

d. After each Customer's initial 10 year period the bill credit will be based on the purchase rate in effect at that time, and may change from year to year.

Further details are provided in the Resource Comparison Proxy Plan of Administration and Arizona Corporation Commission Decision Nos. 75859, 75932, 76295, 78317, 78643, and XXXXX.

PURCHASE RATES

The Company will provide a bill credit for the exported energy based on the following purchase rates:

Tranche 2017	September 1, 2017 through September 30, 2018	$0.12900	per kWh
Tranche 2018	October 1, 2018 through September 30, 2019	$0.11610	per kWh
Tranche 2019 & 2020	October 1, 2019 through September 30, 2021	$0.10450	per kWh
Tranche 2021	October 1, 2021 through August 31, 2022	$0.09405	per kWh
Tranche 2022	September 1, 2022 through August 31, 2023	$0.08465	per kWh

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; however, if the outstanding credits exceed $25, the Company will automatically issue a check to the Customer. Otherwise, the bill credits will carry forward to the following year.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. Electricity must be generated using solar photovoltaic panels;
2. The generator must be interconnected to the Company's distribution grid;
3. The generator must be on-site, installed behind the billing meter, and must serve the residential Customer's load.

Systems of any size are subject to the requirements found in the Arizona Administrative Code Distributed Generation Interconnection Requirements, APS's Interconnection Manual, Interconnection Agreement, and APS's Electric Service Requirements Manual.

SPECIAL CASES

1. Switching from a grandfathered Legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the bill credits for export energy will be based on the annual RCP rate as it changes from year to year excepting where 10 or more years are remaining in the solar grandfathering status. In such instances, the Customer will be eligible for a 10-year lock in the purchase rate then in effect at the time of the switch.

2. Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this rate rider, a material increase in capacity means increasing the capacity by 10% or 1 kW-dc, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW-dc, whichever is greater.

3. Transferring Service. If a Customer moves to a site that is currently being served under Rate Rider RCP, they may continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have a standard Advanced Metering Infrastructure (AMI) meter installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a Customer's interconnection agreement.

4. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies their own electric requirements, and

any excess generation (over and above their own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer Customers who have an Aggregated Peak Load of 5 MW or more and are served under Rate Schedules E-34, E-35, E32-L, E-32 TOU L, E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S.

Customers must have interval metering, Advanced Metering Infrastructure, or an authorized alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the Customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the Customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of Customer load.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of an application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-X.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this AG-X rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the aggregated actual hourly metered load for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Resource Adequacy: To ensure the reliable operation of the grid, each Generation Service Provider will assure they have acquired sufficient resources to satisfy forecasted future loads and planning reserve margins by meeting the following criteria:

1. Resource Adequacy not purchased from APS must be sourced from a specific generating unit or sourced from a specified aggregation of resources which could be a specified balancing authority area.

2. Resources must be identified in advance as described in the AG-X Program Guidelines.

3. Resource Adequacy is in excess of the host balancing authority area or supplier's existing commitments for reliability planning, and that it is dedicated to serving APS customer load. The resource must be able to serve APS customer load during reliability events and cannot be curtailed for another entity except in the case of being sourced from a specified aggregation of Balancing Authority resources and the curtailment is pro-rata with native load of sending Balancing Authority Area.

4. The energy being purchased for Resource Adequacy will be delivered to APS at an agreed upon location via firm or high priority transmission as further described in the AG-X Program Guidelines.

5. Resources must include reserves to meet monthly peak load plus a seasonal planning reserve margin as further described in the AG-X Program Guidelines.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, Customers may enroll on a first come first serve basis. After

the initial lottery, if necessary, Customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

Eligible Customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor Customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate Customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer must apply for service under this rate rider schedule.

The Company will conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer must select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company must enter a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider must provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company will provide transmission, delivery, and network services to the Customer according to normal retail electric service.

The Generation Service Provider must provide resource adequacy for their Customer's load by either purchasing from APS or by demonstrating Resource Adequacy seasonally through the process as described AG-X Program Guidelines.

1. During the first year after the effective date of this Schedule, AG-X Customers must meet Resource Adequacy as follows:

    a. By purchasing Resource Adequacy from APS and paying a transition reserve capacity charge of $6.453 per kW; or

b. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW.

2. After the first year following the effective date of this Schedule, AG-X customers must meet Resource Adequacy as follows:

   a. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW; or

   b. By purchasing Resource Adequacy from APS and paying a reserve capacity charge equal to the unbundled generation demand charge of E-34.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs monthly according to the AG-X Program Guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company will bill the Customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The Customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company will serve as the scheduling coordinator. The Generation Service Provider must provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT, which now reflects the terms of the CAISO imbalance charges.

ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in subsection i above, GSPs would pay a penalty of $3 per MWh.

iii. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again within 12 months from the date of the first notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of the GSP's termination, the Customer will be required to secure a replacement GSP within 60 days, and will be subject to the terms listed in "Default of the Third-Party Generation Provider".

DEFAULT OF THE THIRD-PARTY GENERATION PROVIDER

If the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days of such notification. Prior to execution of any new power contract, the Company will provide the required power to the Customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the Company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the Customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customers may return to the Company's Standard Generation Service under their applicable retail rate schedules if: (1) they provide one year notice to the Company and are receiving Company provided RA; (2) they provide three years notice to the Company where they are

receiving GSP provided RA; or (3) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to Customers under the following conditions. The Company may elect to provide a Customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain one year notice if the Customer had previously been receiving Company provided RA or three years notice if the Customer had previously been receiving GSP provided RA, at which time the Customer returns to the Company's Standard Generation Service under its applicable retail rate schedule. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the Customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;

2. Adjustment Schedule PSA-1 will not apply;

3. Adjustment Schedule EIS will not apply; and

4. The applicable proportionate part of any taxes or governmental impositions, which are or may in the future be assessed based on any of the following will be applied to the Customer's bill:

    a. The Company's gross revenues.

    b. The price or revenue from the electric energy or service sold.

    c. The volume of energy generated or purchased for sale or sold hereunder.

Schedule AG-X charges determined and billed by the Company include:

1. A monthly administrative management fee of $0.00164 per kWh applied to the Customer's billed kWh;

2. A monthly reserve capacity charge applied to 100% of the Customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);

3. Returning Customer charge, where applicable, as described herein;

4. Generation Service Provider Default charge, where applicable, as described herein.

Schedule AG-X Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges will be charged at a rate within the minimum and maximum limits as follows:

    a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
    b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.
    c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges will be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with section iii under Imbalance Services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider,

including but not limited to, the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

AG-X customers that aggregated accounts to meet the 5 MW minimum load size eligibility requirements may add new accounts not previously on their application if their load falls below the 5 MW threshold because of participation in energy efficiency programs.

AG-X customers may grow up to 10% beyond their original allocation in the program.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

RATE SCHEDULE CPP-GS
CRITICAL PEAK PRICING – GENERAL SERVICE

AVAILABILITY

This rate schedule is available to all Customers served on Rate Schedules E-32 M, E-32L, E-32 TOU M, E-32 TOU L, E-34, E-35, and E-221.

DESCRIPTION

Critical Peak Pricing (CPP) events are specific hours within the summer months when the Company is expecting extreme temperatures, high energy (kWh) usage, high market energy costs, or is experiencing a major generation or transmission outage. Customers on this rate rider agree to use less energy during these CPP events. Energy charges during CPP events are higher than the remainder of the summer On-Peak hours, but the Customer also receives a discount for all other energy used during the CPP summer months.

CHARGES

The following charge is in addition to the On-Peak charge in the Customer's rate schedule:

Charge for energy use during Critical Peak hours	$0.25000	per kWh

The following discount will apply to all non-Critical Peak hours during CPP Summer months (June through September):

Rate Schedule E-32 M	$ (0.010351)	per kWh
Rate Schedule E-32 L	$ (0.009533)	per kWh
Rate Schedule E-32 TOU M	$ (0.009266)	per kWh
Rate Schedule E-32 TOU L	$ (0.008680)	per kWh
Rate Schedule E-34	$ (0.008519)	per kWh
Rate Schedule E-35	$ (0.007396)	per kWh
Rate Schedule E-221	$ (0.006116)	per kWh

SERVICE DETAILS

1. Eligible Customers must be able to reduce their usage during CPP events by a minimum of 200 kW. Any reduced load must have otherwise been served specifically by APS generation.

2. Eligible Customers must submit a load reduction plan, which must be approved by the Company prior to participation.

3. This rate rider requires the Customer's usage to be measured with an AMI meter.

4. A Customer cannot be on this rate rider and another demand response program offered by the Company. Customers may participate in this rate rider and the Legacy EPR-6 Rate Rider, but any exported generation during a CPP event will not be applied toward hours in another CPP event.

5. Details of a CPP event are as follows:

    a. CPP events will only be scheduled from 3 p.m. to 8 p.m., Monday through Friday in the months of June through September. CPP events will not be scheduled on holidays (Independence Day on July 4th and Labor Day on the first Monday in September).

    b. At least 6 and no more than 18 CPP events may be scheduled in each calendar year, and each event will last for a period of five hours.

    c. Customers will be notified of a CPP event in advance. By 4:00 p.m. the day prior to the event, the Customer will receive a phone message, e-mail, or text message. The Customer is responsible to watch for this message.

    d. Once noticed, a CPP event will not be canceled.

6. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER DCFC
GENERAL SERVICE
DIRECT CURRENT FAST CHARGING PILOT

DESCRIPTION

This pilot rate rider provides an upper limit to the monthly billed demand, relative to the Customer's monthly kWh usage and billed days, to facilitate the initial deployment of public, fast-charge, electric vehicle charging stations.

AVAILABILITY

This pilot rate rider is available to Standard Offer retail customer service accounts served under rates E-32 TOU Small, E-32 TOU Medium, and E-32 TOU Large, where electricity is consumed only by public, fast-charge, electric vehicle charging stations that are separately metered from other facilities unless those facilities are incidental to the charging load.

This rider is limited to 500 customer service accounts on a first-come, first-served basis and will sunset after the July 2031 billing period.

Other buildings that are on the same site as the vehicle charging facilities will be separately metered and billed under a retail rate, without this rider.

LOAD FACTOR LIMITS

Monthly billing demands are limited to a kW no higher than that which would result in the applicable load factor limit, based on the customer's kWh usage, and billing days during the month. The monthly load factor limits are:

	Monthly Cycle Bills beginning with Cycle 1 Between	Load Factor Limit
Period One	December 1, 2021 through June 30, 2025	25%
Period Two	July 1, 2025 through June 30, 2028	20%
Period Three	July 1, 2028 through June 30, 2031	15%

The monthly billing demand shall be the lower of:

1. The Billing Demand metered and calculated according to the parent rate schedule, or

2. The Limited Demand which equals:
    a. Period One - (Monthly Billed kWh) / [25%*Days*24 hours]
    b. Period Two - (Monthly Billed kWh) / [20%*Days*24 hours]
    c. Period Three - (Monthly Billed kWh) / [15%*Days*24 hours]

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule, other than those specifically modified here, continue to apply.

2. Qualifying direct current fast chargers have a discharge capacity of 50 kW or greater and are available for use by the general public and not restricted.

RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING

AVAILABILITY

This rate rider is available to qualifying residential and non-residential partial requirements Customers with an on-site renewable distributed generation system. Residential Customers with an interconnected on-site solar photovoltaic system are not eligible for this rate rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program and exports energy through the Company's distribution grid. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a Time-of-Use (TOU) rate, the export energy will be netted according to the on-peak and off-peak periods. On-peak export energy will be netted against on-peak energy from the Company and off-peak export energy will be netted against off-peak energy, for all unbundled energy components of the rate that have TOU charges.

PURCHASE RATES

After the December bill, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

BILLING DETAILS

1. All terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for any remaining export energy at the purchase price.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. The generator must be interconnected to the Company's distribution grid;

2. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;

3. For non-residential systems, no system may exceed 125% of connected load for its meter, where connected load is defined as the maximum demand divided by 0.6.

4. For all qualifying residential and non-residential facilities, systems of any size are subject to the requirements found in the Arizona Administrative Code Distributed Generation Interconnection Requirements, APS's Interconnection Manual, Interconnection Agreement, and APS's Electric Service Requirements Manual.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a Customer interconnection agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

    a. Provides part of the Customer's energy requirements at the site where the system is installed;

    b. Uses renewable resources, as defined by the Arizona Corporation Commission, including a fuel cell with the chemical reaction derived from renewable resources or a combined heat and power (CHP) facility as defined by A.A.C. R14-2-2302, to generate energy; and

c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

5. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

RATE RIDER SCHEDULE GPP
GREEN POWER PARTNERS

This rate rider is available to commercial and industrial customers that desire to purchase renewable power from APS. The customer subscribes to a contracted amount of green power and pays a specified price for the power, in addition to their normal retail rate.

APPLICATION

This Rate Rider Schedule GPP is applicable to APS's ("Company") retail Standard Offer business customers served under large and extra-large general service rates unless otherwise specified in the contract. Customers with extra-small, small and medium accounts may also be eligible provided their accounts have an aggregate non-coincident sum of individual peak loads that exceed 1 MW or 5,000 MWh annually. This rider is not available for service accounts participating in Rate Rider AG-X or any successor rate schedule.

The customer must meet the eligibility requirements for the specific green power offering they choose to enroll in.

GREEN POWER OPTIONS

The amount of green energy available for each option under this rate rider will be determined at the sole discretion of the Company. Specific transactions may involve a transfer or retirement of renewable energy credits ("RECs").

Option A

The customer purchases green power from a new APS resource, or group of resources, that is part of the Company's planned resources and in service after January 1, 2021.

The customer subscribes to a specified amount of green power with a purchase commitment of at least one year. The green power will be priced at the time of the offering, and if applicable, a purchase of the RECs may involve an additional charge. The prices will be specified in the customer contract and may be revised from one resource procurement to the next. In the event RECs are transferred or retired as part of these agreements, such RECs will not be used for compliance to meet the state Renewable Energy Standard ("RES") and any revenue associated with the transfer of RECs will be credited to customers. All contracts will be submitted to the Arizona Corporation Commission ("ACC") for approval.

Option B

The customer purchases green power from a new APS resource, or group of resources, that is part of the Company's planned resources and in service after January 1, 2021.

The customer desires the facility to be located in a designated area or specific parcel. The customer subscribes to a designated amount of green power for a minimum of 20 years.

The pricing for this option will reflect the locational cost differential as determined by the Company. If applicable, a purchase of the RECs may involve an additional charge. The prices will be specified in the customer contract and may be revised from time-to-time. All contracts will be submitted to the ACC for approval.

Option C

The customer purchases green power from a new APS resource, or group of resources, that is not part of the Company's planned resources or seeks to accelerate acquisition of a planned resource. The participating customer will be responsible for all incremental costs, including capital costs.

The customer subscribes to a fixed amount of green power with a purchase commitment for the output of the facility over a mutually agreeable term. The green power will be priced at the time of the offering, and if applicable, a purchase of the RECs may involve an additional charge. The prices will be specified in the customer contract and may be revised from time-to-time. All contracts will be submitted to the ACC for approval.

CHARGES

The customer shall pay a green power price in addition to the customer's full retail rate. All provisions and charges in the customer's rate schedule will continue to apply.

The green power price will be as calculated by the Company, based on resource procurement costs for specified green power facilities and other relevant factors, as discussed above, and the avoided cost of the green power.

The prices will be specified in the customer contract and may be revised from time-to-time.

The green power price for all options will be priced in the range from a minimum of $0.001 per kWh up to a maximum of $0.015 per kWh.

CONTRACT

Customer shall enter into a green power contract with the Company prior to receiving service under this rate rider. The agreement will specify, among other things, the customer accounts receiving green power, the amount of green power, the green power price, the term of the agreement, and the customer credit information.

RATE RIDER GS-EV
GENERAL SERVICE
ELECTRIC VEHICLE RIDER

This page is being included as a placeholder pending the resolution of the APS application for the GS-EV rider in Docket 19-0236.

AVAILABILITY

The Interruptible Rate Program (IRR) rate schedule is available to Customers on Rate Schedules E-34 or E-35.

Customers cannot participate in Rate Rider IRR in conjunction with other demand response programs and rate riders such as Critical Peak Pricing (CPP-GS), Peak Solutions, Power Partners, and other programs and rates that may be offered from time to time.

Participation under this schedule is subject to the availability of required metering and communication equipment compatible with the Customer's applicable retail rate schedule and electrical service configuration and availability of the necessary load data to establish the Baseline Load. The Company will provide any required equipment.

DESCRIPTION

Rate Rider IRR is a demand response program where a Customer has the ability to choose how many hours and days per year the Customer's energy usage can be interrupted during the summer months. The Company's request to lower energy usage is called an event.

The Customer agrees to the amount of load reduction in an executed contract. Customers may enroll in this rider in the months of October through December in any calendar year.

TIME PERIODS

Events may occur June through September, all days of the week including holidays, from 12 noon to 8 p.m.

Customers will choose the maximum number of Events and hours per Event per Program Year from the following options:

Option	Max Hours per Event	Max Number of Events	Max Interruptible Hours
1	4	20	80
2	8	10	80

APS will not call more than one interruption event per day. APS will call at least 2 events per year. The Customer will choose either a 30-minute or 2-hour notice period. The Company will notify the Customer of an event by e-mail, cell phone, land line, text message or pager as chosen by the Customer. The Customer is responsible for receiving notification and acknowledging receipt of that notification to the Company within 15 minutes of receipt.

CREDITS

The Customer will receive a capacity credit and an energy credit for reducing hourly usage during all event hours. The capacity credit will be derived by multiplying the average actual interrupted demand for all events in a calendar year by the Customer by the applicable capacity credit rate. The energy credit will be derived by multiplying the energy reduced for all events in a calendar year by the Customer by the applicable energy credit rate.

The credits will be issued once a year in November through a direct payment or a bill credit, at the Company's option.

The credit rates will be revised from time to time, as approved by the Arizona Corporation Commission, but will not change during the Program Year.

All Customers participating in a five-year agreement will be subject to any revised credit rates for the calendar year, regardless of the number of years remaining on their contract.

1 Year Agreement Credit Rate:

Option	30 Minute Notice		2-Hour Notice	
	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$7.975	$0.09969	$7.178	$0.08972
2	$5.995	$0.07493	$5.395	$0.06745

5 Year Agreement Credit Rate:

Option	30 Minute Notice		2-Hour Notice	
	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$9.882	$0.12353	$8.894	$0.11117
2	$7.428	$0.09285	$6.685	$0.08356

If at least 50% of the data necessary to calculate kW is available, any missing kW values will be estimated using the average of the available hourly data for a specific event. If less than 50% is available, the missing kW values will be estimated using the Customer's agreed level of load reduction in the contract.

SERVICE DETAILS

1. For any Event Year, if the Average Shortfall Demand is greater than 5% and less than or equal to 10% of the Required Interrupted Demand, the Customer will receive 50% of the capacity credit. If the Average Shortfall Demand exceeds 10% of the Required Interrupted Demand, the Customer will not receive a capacity credit. In either case, the Customer will continue to receive 100% of the energy credit. The penalty will not apply to the first Event of the Customer's first Program Year on Schedule IRR.

2. If the Customer terminates participation prior to the contract term in a five-year agreement, the Customer will pay the Company a penalty equal to the relevant Capacity Credit rate times the Required Interrupted Demand from the most recent Event Year (with a minimum of 500 kW) times the number of years remaining on the agreement. The total penalty shall be assessed at the time of termination.

3. If a Customer terminates participation prior to the contract term in a one-year or a five-year agreement, the Customer will not be allowed to participate in the rate for the two subsequent years.

4. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

This rate rider is for retail customers that were awarded hydro power from a federal dam. It explains how APS will deliver the power to the Customer and net it off of their retail bill. This program supports Arizona's effort to take full advantage of the State's allocation of hydro-electric power from Hoover Dam, Parker Davis Dam and Glen Canyon Dam.

APPLICATION

This Rate Schedule PPR Preference Power Rider ("Schedule PPR") is applicable to APS's ("Company") retail Standard Offer customers who receive a firm electric service allocation of preference power from the Western Area Power Administration ("WAPA"), an agency of the U.S. Department of Energy or the Arizona Power Authority ("APA"). Schedule PPR is applicable to all Preference Power allocations awarded from WAPA or APA after January 1, 2007.

Schedule PPR may be used with the following retail rate schedules: E-34, E-35, E32-L, E32-M, E32TOU-L, E32TOU-M and E-221 or successor rate schedules.

All provisions of the Customer's retail rate schedule will apply in addition to Schedule PPR.

Definitions

1. Preference Power Allotment ("Allotment", "Preference Power"): Hydro power, energy and capacity, awarded to the Customer from WAPA as recorded in the Federal Register or from the Arizona Power Authority ("APA"), as specified in Electrical Supply Agreement.

2. Hydro Power: Electricity produced from generators that are run by moving water.

3. Firming Power: In any given month or year the actual amount of Preference Power that the Customer receives may be less than their Allotment. In this case the Customer is allowed to arrange for other power, up to the energy and capacity specified in the Allotment, to make up the difference.

4. Layoff Power: Preference Power purchased from, or sold to, another allottee. Layoff Power purchased from another allottee may be used as Firming Power. Any Layoff Power purchases made above the Customer's Allotment are not eligible for bill crediting under this program.

Preference Power Program

1. APS will schedule all of the Preference Power, including any Firming Power and Layoff Power, according to APS's system requirements and manage any delivery and coordination details. Any Preference Power not scheduled by APS, or not available during the Company's desired time periods, will not be eligible for bill crediting under this program.

2. APS will take delivery of the Preference Power, up to the Customer's Allotment, at a delivery point specified by APS in an Electrical Supply Agreement and transport it to the Customer's business location at no additional charge above the current retail rate for power transmission and delivery. The standard delivery point for Preference Power from the Hoover Dam will be the Mead substation near Boulder City, Nevada.

3. The Customer will designate one retail account, as the primary account to receive the Preference Power. The Customer may also designate a back-up account in the event the load from the designated primary account falls below the Preference Power Allotment in an occasional month. If the Customer's Preference Power Allotment is greater than any single account then up to three accounts may be used.

4. The Customer may change their Preference Power account designations once per calendar year.

5. The amount of Preference Power including any Firming or Layoff Power will be limited to the Customer's annual and seasonal Allotment. However, the Customer may schedule additional Preference Power during the summer season (March – September) and less during the winter (October – February), as long as the annual total does not exceed the Allotment.

6. The amount of the Preference Power credit will also be limited to the kWh on the Customer's monthly retail bill for the designated account(s).

7. Preference Power credits are not eligible for direct access Customers or those on rate rider AG-X.

Bill Credit

The Customer's monthly bill will first be calculated without the Preference Power according to the Customer's standard retail rate schedule.

The Preference Power capacity and energy scheduled for the month will then be credited off of the retail capacity and energy charges for generation service based on the credit rates in this rate rider. The Preference Power energy will also be credited off of the kWh charges in Adjustment Schedule PSA-1, which are revised annually.

The credit rates include the unbundled generation capacity demand charges and energy charges consistent with APS's retail rates for medium, large and extra-large business Customers and adjusted for average system kWh line losses. The capacity demand charges in the retail rates are converted to equivalent energy (kWh) amounts based upon class billing determinants in the most recent rate case.

The credit rates will be revised from time to time to reflect changes in the retail rates as approved by the Arizona Corporation Commission.

The credit rates are based on the size of the capacity Allotment, not the specific retail rate for the designated account(s).

	Preference Power Credit Rates ($/kWh) (excluding credit for schedule PSA-1)	
Preference Power Allotment	Summer (May - October)	Winter (November - April)
1MW and above	$0.06034	$0.06034
401 kW - 999 kW	$0.07232	$0.05428
0 kW - 400 kW	$0.07750	$0.06032

Contract

Customer must enter into an "Electrical Supply Agreement for Customers with Preference Power" with the Company prior to receiving service under Schedule PPR. This agreement will specify, among other things, the Customer accounts receiving Preference Power and the amount of the Preference Power Allotment.

RATE RIDER SD-1
GENERAL SERVICE
SCHOOL DISCOUNT RIDER

AVAILABILITY

This rate rider is available to all public elementary and secondary schools (K through 12) served under rate schedules E-32 XS, E-32 XS D, E-32 S, E-32 M, E-32 L, E-32 TOU XS, E-32 TOU S, E-32 TOU M, E-32 TOU L, GS-Schools M, and GS-Schools L.

DESCRIPTION

This rate rider provides a monthly bill discount for a public elementary and secondary (K-12) school requesting service under this rate rider.

DISCOUNT

The following discount will apply to the Customer's monthly billed kWh:

Discount	$0.00293	per kWh

SERVICE DETAILS

1. The discount will be applied to the monthly billed kWh prior to the application of taxes, regulatory assessment, and franchise fees.

2. This discount is not available to Direct Access Customers or Customers on Rate Rider AG-X.

3. Customers may not receive discounts under both this rider and the E-32 L or E-32 TOU L Aggregation Discount at the same time.

4. All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

AVAILIBILITY

This rate rider is available to eligible public elementary and secondary schools (K through 12) including charter schools, and eligible government customers served under rate schedules E-32 S, E-32 M, E-32 L, E-32TOU S, E-32TOU M, E-32TOU L, GS-SCHOOLS M, GS-SCHOOLS L, E-34, and E-35.

A Customer on this rate rider cannot also be on a Partial Requirements rate rider or rate rider AG-X.

This rate rider was frozen on August 19, 2017. This means no new Customers will be served under this rider after that date, and any Customer that moves to another available rate rider cannot move back to this one. Customers may remain on this rider for up to 20 years from the date an on-site distributed generation system was connected to the Company's distribution grid.

DESCRIPTION

This rate rider provides a 20-year fixed charge for a portion of the Customer's monthly energy usage equal to the energy produced by a Company-owned on-site solar distributed generation system that is directly connected to the Company's distribution grid.

SOLAR ENERGY

Solar Energy, which is used in the calculation of the Solar Charge below, is the expected monthly kWh production from the Company's solar equipment over time. The applicable Solar Energy is calculated by multiplying the kW-DC nameplate generator rating of the system by an average monthly production factor of 90 kWh-AC per kW-DC.

CHARGES

The Customer's monthly bill will be calculated in accordance with the current applicable rate schedule except:

The monthly bill will include a Solar Charge, which is the Solar Energy multiplied by the charges listed below:

Applicable Retail Rate Schedule	Solar Charge	
E-32 S, E-32 M	$0.07665	per kWh
E-32 L	$0.04660	per kWh
E-32TOU S, E-32TOU M, E-32TOU L	$0.05502	per kWh

FROZEN

GS-SCHOOLS M, GS-SCHOOLS L	$0.07571	per kWh
E-34	$0.04236	per kWh
E-35	$0.04128	per kWh

BILLING DETAILS

1. The monthly bill will be based on the Customer's total metered usage net of the Solar Energy, but the netted kWh shall not be less than zero. The netting will be applied as follows:

   a. For Customers on Rate Schedules E-32TOU S, E-32TOU M, E-32TOU L, and E-35:

On-Peak kWh	50.0%
Off-Peak kWh	50.0%

   If the net kWh is less than zero for either the On-Peak or Off-Peak period, the remaining kWh will be netted from the other time period, but the netted amount will not be less than zero.

   b. For Customers on Rate Schedules E-32 S and E-32 M:

First 200 kWh per kW	60.0%
All additional kWh	40.0%

   If the netted kWh is less than zero for either tier, the remaining kWh will be netted against the other kWh tier, but the netted amount will not be less than zero.

   c. For Customers on Rate Schedules GS-SCHOOLS M and GS-SCHOOLS L:

   Solar Energy shall be netted from the On-Peak and Off-Peak kWh as follows:

	On-Peak	Off-Peak
Summer Peak (May-Oct)	50.0%	50.0%
Winter (Nov-Apr)	30.0%	70.0%

FROZEN

If the net kWh is less than zero in any period, the remaining kWh will be applied first to the On-Peak, then to the Off-Peak period if necessary, but the resulting kWh in any period will not be less than zero.

d. For Customers on Rate Schedules E-32 L and E-34, Solar Energy will be netted from the total monthly kWh, but the resulting kWh will not be less than zero.

2. Any reductions to the Customer's monthly kWh billed under Adjustment Schedule REAC-1 due to participation in Green Power Rate Riders GPS-1, GPS-2, and GPS-3 will be capped at the Customer's total metered kWh net of the Solar Energy provided in this rider.

3. Solar Energy is netted against the metered kWh from the single service entrance section where the system is installed and will not be netted against metered kWh from any other points of delivery at either the same Customer site or other sites. If a Customer has totalized metering service provided under Service Schedule 4, the Solar Energy will not exceed the metered kWh from the single service entrance section where the solar facility is installed.

FROZEN

AVAILABILITY

This rider rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

This rider rate schedule is applicable to retail Customers who obtain any part of their electric requirements from on-site generation equipment with a continuous nameplate rating of 100 kW or greater for other than emergency purposes, requiring Supplemental and Back-up or Maintenance Power and energy from the Company. Direct Access Customers are not eligible for service under this rate schedule. All provisions of the Customer's applicable retail rate schedule will apply except those specifically modified herein. Total measured demand at the Customer's meter will be used to determine the applicable retail rate schedule.

DEFINITIONS

1. Back-up Contract Demand − The specified demand, in kilowatts, of Back-up Power that the Customer contracts with the Company to supply and which the Company agrees to have available for delivery to the Customer. The Back-up Contract Demand shall be established by agreement between Customer and Company. The level of Back-up Contract Demand shall not exceed the total output capacity of the Customer's generation facilities.

2. Back-up Power − The kW of Back-up Contract Demand supplied by the Company to the Customer. Back-up Power shall be determined for each day of the Billing Period containing on-peak hours. The kW of Back-up Power each day shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Back-up Power during the on-peak hours of the day. The Back-up Power for the Billing Period shall be the sum of the Back-up Power for each day of the Billing Period. For each fifteen-minute period, Back-up Power shall equal the Measured Demand minus the Supplemental Contract Demand but shall not be less than zero nor greater than the Back-up Contract Demand.

3. Billing Period − The period of approximately thirty (30) days intervening between regular successive meter reading dates. There shall be twelve (12) billing periods per year.

4. Excess Power − Excess Power is power supplied by the Company to the Customer in excess of the Total Contract Demand. The kW of Excess Power for the Billing Period shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Excess Power during the Billing Period. For each fifteen-minute period, Excess Power shall equal the Measured Demand minus the Total Contract Demand but shall not be less than zero.

5. Maintenance Power - Electric power and energy made available by the Company to a Customer during the scheduled maintenance periods established in accordance with the provisions of this schedule to replace Back-up Power. Maintenance Power shall not exceed the Back-up Contract Demand.

6. Measured Demand - The fifteen (15) minute Demands (Power) in kilowatts as shown by or computed from the readings of the Power (Demand) meter located at the Company's point of delivery for on-peak and off-peak periods during the Billing Period.

7. Measured Energy - The electric energy in kilowatt-hours as shown by or computed from the readings of the kilowatt-hour meter located at the Company's point of delivery.

8. Supplemental Contract Demand - The specified demand in kilowatts of Supplemental Power that the Customer contracts with the Company to supply and which the Company agrees to have available for delivery to the Customer

9. Supplemental Power – The kW of Supplemental Contract Demand supplied by the Company to the Customer. The kW of Supplemental Power for the Billing Period shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Supplemental Power during the Billing Period. For each fifteen-minute period, Supplemental Power shall equal the Measured Demand but shall not be less than zero nor greater than the Supplemental Contract Demand.

10. Total Contract Demand - The sum of the Supplemental Contract Demand and the Back-up Contract Demand.

DETERMINATION OF SUPPLEMENTAL AND BACKUP CONTRACT DEMAND

The Supplemental Contract and Backup Demand shall be initially established by agreement between the Customer and the Company, and shall be reset annually based on the average daily maximum Measured Demand over the six months, May through October of the most recent year.

MONTHLY RATES

The bill shall be the sum of the amounts computed below, including any applicable adjustments:

A. Basic Service: The Basic Service and Revenue Cycle Service Charges included in the Customer's applicable General Service rate schedule will apply each month.

B. Supplemental Power and Associated Energy: Supplemental Power and Associated Energy will be provided in accordance with the rate levels contained in the Customer's applicable

General Service rate schedule, excluding the monthly Basic Service and Revenue Cycle Service Charges, and also excluding delivery charges associated with Back-up Contract Demand.

C. Delivery Charges: The unbundled delivery charge contained in the Customer's applicable General Service rate schedule multiplied by the amount of Back-up Contract Demand.

D. Back-up Power Charges:

Rate Schedule E-34 Customer - On-Peak:	$ 0.775 per kW Day
Rate Schedule E-32 L Customer - On-Peak:	$ 0.157 per kW Day
During Scheduled Maintenance:	One Half (1/2) the On-Peak Charge
Off Peak:	No Charge

On-Peak Periods:	9 a.m. to 9 p.m., weekdays
Off-Peak Periods:	All other hours

The Power Charge for Back-up Power is billed on a per day basis and is based on the fifteen (15) minute period of the Customer's greatest use of Back-up Power during on-peak hours each on-peak day. For each fifteen-minute period, Back-up Power shall equal the Measured Demand minus the Supplemental Contract Demand but shall not be less than zero nor greater than the Back-up Contract Demand.

E. Excess Power Charges:

Secondary Service:	$ 65.676	per kW
Primary Service:	$ 62.342	per kW
Transmission Service:	$ 45.764	per kW

F. Back-up, Maintenance and Excess Energy: All Back-up, Maintenance, and Excess Energy shall be billed in accordance with the customer's applicable General Service rate schedule.

MAINTENANCE REQUIREMENTS

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per generation unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months, as defined in the Customer's applicable general service rate schedule. Customer shall provide Company with its planned maintenance schedule 90 days in advance of any planned maintenance in order for the Company to coordinate Customer's scheduled maintenance with that of the Company. Upon

review, Company shall either approve Customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

METERING

The Company will install, at the Customer's expense, a bi-directional meter at the point of delivery to the Customer (Supply Meter) and meter(s) at the point(s) of output from each of the Customer's generators (Generator Meter) if required. All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company.

TOTAL CONTRACT DEMAND, SUPPLEMENTAL CONTRACT DEMAND, AND BACK-UP CONTRACT DEMAND

The Customer shall contract for Total Contract Demand. This shall be the sum of the Supplemental Contract Demand and the Back-up Contract Demand. The Customer may elect to increase Total Contract Demand by increasing Supplemental Contract Demand and/or Back-up Contract Demand prospectively at any time, provided there are facilities of adequate capacity, by providing notice to the Company. Any increase in Total Contract Demand shall establish a new Total Contract Demand which shall be in effect for the term of the contract, unless superseded by subsequent increases in Total Contract Demand.

TERMINATION PROVISION

Should Customer cease to operate his generation unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

UNUSUAL UTILITY OPERATING CONDITIONS

If the Company is in need of additional power requirements due to equipment failure or other unusual conditions, the Customer may provide excess generation to Company at Company's request. The Company will pay the Customer for any energy purchased at the per kWh monthly firm purchase rate which is negotiated on a case-by-case basis.

TERMS AND CONDITIONS

Customer must enter into an Agreement for Interconnection and an Electric Supply Agreement which shall establish all details related to interconnection and other required service standards. Qualifying Cogeneration and Small Power Production Facilities (QFs) meeting Public Utility Regulatory Policy Act of 1978 criteria shall be permitted to sell excess power and energy subject to the provisions and rates specified in a Purchase Supply Agreement between Company and Customer. Customers who install facilities that do not meet QF standards will not have the right to sell power and energy to Company under this rate schedule. However, should Customer desire to do so, Customer may seek to enter into a new Service Agreement which would set forth the applicable purchase rates, terms and conditions for interconnection and for the sale of excess power to the Company. Customers cannot combine this rate with any other rate riders.

RATE RIDER SCHEDULE E-56 R
CLASSIFIED SERVICE
PARTIAL REQUIREMENTS - RENEWABLE

AVAILABILITY

This rate rider schedule is available to Customers with a Qualifying Renewable Facility capable of supplying all or a portion of its power requirements.

DESCRIPTION

This rate rider describes how the Company will bill Customers with an on-site Qualifying Renewable Facility requiring Supplemental and Standby Power and energy from the Company. This rate rider also describes how the Company will purchase any Excess Generation from that same Customer.

All provisions of the Customer's retail rate schedule will continue to apply except as noted below.

TIME PERIOD

For purposes of this rider the On-Peak and Off-Peak hours are as specified under a Customer's retail parent rate schedule.

The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider. The monthly bill will consist of the following charges, plus adjustments:

1. Supplemental Service:

    a. Supplemental demand and energy will be determined and billed according to the Customer's retail rate schedule.

2. Standby Service Charges:

    a. Standby Demand will be the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter Equipment at the time the Customer's Supply Meter registers the highest 15-minute integrated kW demand during the billing month. For Customers served under a time-of-use rate, Standby Demand will be determined for the applicable on-peak and off-peak periods.

    b. Standby Energy will be the kWh measured on the Generator Meter Equipment during the billing month.

c. The Standby Service charge will be the unbundled delivery demand charge contained in the Customer's retail rate schedule multiplied by the Standby Demand. For Customers served under a time-of-use rate, this amount will be calculated for the applicable on-peak and off-peak periods; plus

d. The unbundled delivery energy charge in the Customer's retail rate schedule (if any) multiplied by the Standby Energy.

e. If the applicable rate schedule does not have unbundled charges, standby service will be based on the demand charge in the Customer's retail rate schedule less the unbundled transmission charge in Rate Schedule E-32 L, the result multiplied by the 15 minute integrated kW measured on the Generator Meter during the Customer's monthly peak demand.

PURCHASE RATES

The Company will record and purchase the Excess Generation from the Customer at the applicable per kWh seasonal non-firm purchase rates provided in Rate Rider Schedule EPR-2.

SERVICE DETAILS

1. Definitions

a) Qualifying Renewable Facility – A facility for the production of electricity that:

i. Is operated by or on behalf of the participating Customer and is located on their premises and;
ii. Provides part or all of the Customer's energy requirement at the site where the system is installed;
iii. Uses renewable resources, as defined by the Arizona Corporation Commission, to generate energy;
iv. Has a nameplate capacity continuous AC service rating of greater than 100 kW and;
v. Is interconnected with and can operate in parallel and in phase with the Company's existing distribution system.

b) Partial Requirements Service - Electric service provided to a Customer that has an interconnected generator, where the generation output first supplies the Customer's electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

c) Non-Firm Power - Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided, and the power can be interrupted by the Customer at any time.

d) Excess Generation - Equals the Customer's generation (kWh) in excess of their load at any point in time as metered by the Company. Excess Generation is computed for on-peak and off-peak billing periods.

e) Firm Power - Electric power which is supplied by the Customer's generator with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources. Firm Power will be determined in accordance with Rate Schedule EPR-2.

f) Generator Meter Equipment – Equipment which measures the demand and energy output of the Customer's generator. For Customers with multiple generators, such equipment will consist of one meter for each generator.

g) Supplemental Service - Demand and energy provided by the Company to the Customer to augment the power and energy provided by Customer's generation facility.

h) Supply Meter – Equipment which measures the demand and energy provided by the Company to the Customer and may also measure the excess generation flowing from the Customer generator back to the Company.

i) Standby Service - Demand and energy provided by the Company to the Customer to backup the power and energy from the Customer's generation facility.

2. Supplemental Service will be provided at three phase at approximately 60 Hertz with a delivery voltage as specified in the Electric Supply Agreement.

3. The Company will install, at the Customer's expense, a bi-directional meter at the point of delivery to the Customer (Supply Meter) and a meter at each point of output from each of the Customer's generators (Generator Meter Equipment). All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company. A bi-directional meter may not be required if the Customer cannot be served through a bi-directional meter, or if the generating capacity of the Qualifying Renewable Facility is less than 20% of the Customer's lowest billing demand over the 12 months prior to seeking enrollment in Schedule E-56R, or as otherwise determined by the Company through available information, or if the Customer agrees that they do not intend to be compensated for any Excess Generation.

4. The Company will not record or purchase Excess Generation for Customers not served with a bi-directional meter.

5. Customers cannot combine this rate with another partial requirements rate.

6. Customer must enter into an Interconnection Agreement with the Company.

RATE RIDER EPR-2
PARTIAL REQUIREMENTS SERVICE FOR QUALIFIED FACILITIES OF 100 kW OR LESS

AVAILABILITY

This rate rider is available to Customers with a qualifying on-site cogeneration or small power production facility (QF) with a generating nameplate capacity of 100 kW-ac or less which is interconnected to the Company's distribution grid. Contracts between APS and QFs larger than 100kW will be consistent with Decision Nos. 52345 and 77512.

DESCRIPTION

This rate rider describes how the Company will bill a Customer with an on-site QF. A partial requirements Customer has on-site generation that serves some of their electrical needs and relies on the Company for additional electrical services. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

TIME PERIODS

The On-Peak and Off-Peak purchase rates below will be applied to the specific On-Peak and Off-Peak hours under a Customer's retail rate. If the Customer's retail rate has a Shoulder-Peak period, these hours will be credited at the On-Peak purchase rate.

The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

PURCHASE RATES

The export energy will be acquired by the Company in exchange for a credit on the Customer's monthly bill, based on the following rates for summer and winter seasons:

	Summer	Winter	
On-Peak Non-Firm Rate	$0.02989	$0.03040	per kWh
Off-Peak Non-Firm Rate	$0.02897	$0.02831	per kWh
On-Peak Firm Rate	$0.04297	$0.03040	per kWh
Off-Peak Firm Rate	$0.03009	$0.02831	per kWh

BILLING DETAILS

All terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

SERVICE DETAILS

1. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the Customer's own generation facilities).

2. Customers cannot combine this rate rider with another partial requirements rate or rate rider.

3. A Qualifying Facility (QF) is a cogeneration or small power production facility which meets the requirements for QFs under 18 CFR, Chapter 1, Part 292, Subpart B of the Federal Energy Regulatory Commission requirements. To qualify for this rate rider, the QF must have a nameplate continuous output power rating of 100 kW or less.

4. Export energy equals the Customer's generation (kWh) in excess of their electricity needs at any point in time as metered by the Company. Export energy is metered and accumulated instantaneously for any part of an hour.

5. Non-Firm Power is electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

6. Firm Power is power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

7. Electric sales to the Company must be single phase or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises).

8. Power sales and services supplied by the Company to the Customer in order to meet its electric requirements will be priced at the Customer's retail rate schedule.

9. Customers served under this rate schedule must have an AMI meter that will register and accumulate the net electrical requirements of the customer. The AMI meter will be provided at no additional cost to the customer.

10. The Company provides service under this rider in accordance with its Interconnection Requirements Manual, which has provisions that may affect the Customer's bill. Special provisions may also be included in a Customer interconnection or purchase agreement.

Demand Side Management Adjustment Charge
Plan of Administration

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1. General Description

This document describes the plan for administering the Demand Side Management Adjustment Charge (DSMAC) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (Commission) in Decision No. 67744, and later revised by the Commission in Decision Nos. 71448, 73183, 74406, 76295, 78317, 78585 and XXXXX. The DSMAC provides for the recovery of Demand Side Management (DSM) program costs, including energy efficiency (EE) and demand response programs (DR), and DSM performance incentives as well as the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of EE savings and distributed generation (DG) determined to have occurred as described herein The lost fixed costs to be recovered include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution. The DSMAC is applied to Standard Offer or Direct Access customer bills as a monthly kilowatt-hour charge (for Residential customers and General Service customers served in accordance with non-demand billed rate schedules), or kilowatt demand charge (for General Service customers served in accordance with demand billed rate schedules), unless the customer's current rate has alternate provisions. The charges will be filed with the Commission annually when APS submits the DSM Implementation Plan (DSMIP) for approval. This will occur November 30th of each year. If approved by the Commission, the charge will be effective the following year beginning with billing cycle 1 of the October revenue month and will not be prorated.

Recovery of all applicable program costs and incentives will be allowed for all programs that have been approved by the Commission.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Current Period – The most recent adjustment year.

DG Savings – The amount of MWh sales reduced by DG. Where available, APS will use meter data to calculate DG system savings. Each year, APS will use DG production data to calculate the savings. The calculation of DG Savings will consist of the following by class:

- Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.

Excluded MWh Production: The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the LFCR portion of the DSMAC adjustor rate calculation as shown in Schedule 9 of the compliance filing list.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The Return on Equity (ROE) authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

EE (or DSM) Programs – Any program approved in APS's DSM Implementation Plan.

EE Savings – The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

- Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.
- Current Period: The EE related sales reductions (MWh). Each year, APS will use MER verified data to report EE savings.
- Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of actual EE Savings achieved by customers on Excluded Rate Schedules.

Excluded Delivery Revenue – 50% of any delivery demand (kW) revenue as determined in Decision No. XXXXX and calculated on Schedules 6 and 7.

Lost Fixed Cost Rate – A rate determined at the conclusion of APS's most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue (LFCR) – The amount of fixed costs not recovered by the utility because of EE and DG during the period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Performance Incentives (PI) - Represents a percentage of the net economic customer benefits (benefits minus costs) from approved EE programs based on a graduated scale that is capped at a maximum of $/kWh of first-year EE savings achieved.
Program Costs (PC) - Allowable expenses include, but are not limited to: program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement DSM programs (EE and DR) that are approved by the Commission in the DSMIP. For those DSM programs that may generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Transition Balance – The Lost Fixed Cost Revenue balance as calculated in compliance during that period per Decision No. 73183 and modified in Decision No. 74202.

True-up (TU) – A reconciling of authorized PC and LFCR amounts from the previous approved Plan.

3. Rate Schedule Applicability

The DSMAC shall be applied monthly to every retail Standard Offer or Direct Access service, unless exempted by Commission order.

4. Performance Incentive

Performance Incentives (PI) - Represents a percentage of the net economic benefits (benefits minus costs) from approved EE and DR programs based on a graduated scale that is capped at a maximum $/kWh of first-year savings achieved.

Achievement Relative to Annual Goal Approved in APS's DSM Implementation Plan	Performance Incentive as % of Energy Efficiency and Demand Response Net Benefits	Performance Incentive Cap*
< 85%	0%	Performance Incentive Will Not Exceed $0.0125/kWh Saved
85% to 95%	6%	
96% to 105%	7%	
> 105%	8%	

*The PI cap is based on the annualized incremental first year EE savings generated plus the equivalent kWh of DR kW savings achieved

5. Determination of the Adjustor Charge

By November 30th of each year, APS will file a revised DSMAC with supporting documentation in the DSMIP. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods.

The DSMAC calculation will be for purposes of recovering PC, PI, LFCR under the DSM Program and will be developed based on the following formula:

$$DSMAC = \frac{PC + PI + LFCR + TU + I}{Sales}$$

Where:

PC = Program Costs as defined in section 2 forecast for the plan year.

PI = Performance Incentives as defined in section 2 forecast for the plan year.

LFCR = Lost fixed cost recovery as defined in section 2.

TU = Any "true-up" balance.

I = Interest associated on any over recovery of DSMAC costs for the prior period. The interest rate is based on the one-year Nominal Treasury Maturities rate from the Federal Reserve H-15 or its successor publication. The interest rate shall be adjusted annually on the first business day of the calendar year.

Sales = Forecast energy (kWh) sales under applicable electric rate schedules during the Adjustor Period in which this adjustor will be effective.

Adjustor Period = The 12-month period beginning with the first billing cycle during March of the current year and ending with the last billing cycle of February of the next year.

The DSMAC for General Service customers that are billed on demand will be calculated as a per kW charge. The DSMAC for General Service customers that are not billed on demand will be calculated as a per kWh charge. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSMAC.

For residential billing purposes, the DSMAC and the Renewable Energy Adjustment Charge (REAC) are combined and will appear on customer bills as the "Environmental Benefits Surcharge." For general service and other non-residential customer billing, the Company may, but is not required to, provide for such combined billing of the REAC and DSMAC. In any event, each adjustor will be kept separate in the Company's books, records, and reports to the Commission.

a. In the event that PC or LFCR are more or less than DSMAC revenues collected as of the last available period prior to filing, the over or under collection will be included in the TU balancing account. Any over collection will earn interest. Under collections will not accrue interest.
b. LFCR Annual Incremental Cap will be subject to an annual 1% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR calculated increase exceeds 1% of Applicable Company Revenues, any amount above the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance
c. Earnings Test - Any requested increase in the Schedule DSMAC adjustment mechanism related to LFCR will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold. If the results of the Earnings Test are higher than the Earnings Test Threshold, the Lost Fixed Cost Revenue recovered through Schedule DSMAC will be limited to the amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule DSMAC in a future year. The results of the Earning Test will only affect recovery with respect to LFCR and not affect any recovery associated with EE or DSM Programs.

6. Compliance Reports

APS will provide comprehensive Compliance Reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

Schedule 1: DSMAC Annual Adjustment
Schedule 2: LFCR Annual Incremental Cap Calculation

Schedule 3: LFCR Calculation
Schedule 4: LFCR Historical Transition
Schedule 5: LFCR Test Year Rate Calculation
Schedule 6: Distribution Revenue Calculation – General Service
Schedule 7: Distribution Revenue Calculation – Residential
Schedule 8: Annual DG Installation Report
Schedule 9: Annual Earnings Test
Schedule 10: Capital Structure

7. Review Process

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Section 5. APS will file an updated adjustor charge each year with its DSMIP on November 30th. If approved by the Commission, changes in the DSMAC will go into effect on the first billing cycle of October of the following year.

The EIS and this POA is cancelled as of XXXX as ordered in Decision No. XXXX.

The LFCR and this POA is cancelled as of XXXX as ordered in Decisions No. XXXX.

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism (PSA) approved for Arizona Public Service Company (APS) by the Commission on June 28, 2007 in Decision No. 69663, and subsequently amended by the Commission in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), 76295 (August 18, 2017), 78317(November 9, 2021), and XXXXX (Date TBD). The PSA provides for the recovery of fuel and purchased power costs and other production-related variable costs to the extent that those costs deviate from the amount recovered through APS's Base PSA Cost ($0.038321 per kWh) authorized in Decision No. XXXXX, on TBD.

Non-fuel production costs included in the PSA relate to environmental chemical expenses, which vary directly with power plant production. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The PSA allows for the refund or recovery of said costs that deviate from the base cost amount of $0.000500 per kWh[1].

In addition, the PSA allows for the refund or recovery of the net margins from sales of emission allowances to the extent the actual sales margins deviate from the base cost amount of ($0.000001) per kWh,[2] and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.

APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur California's carbon emission allowance costs when doing so is not an economical choice for APS's Arizona ratepayers.

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and environmental chemical costs for fossil fuel production, and

[1] $0.000500 per kWh is the result of the following: (2015 chemical costs of $13,527,111 / 2015 test year native load sales of 27,030,686 MWh) / 1000.
[2] ($0.000001) per kWh is the result of the following: (2015 net gains from sales of SO_2 allowances of $25,181 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

margins on the sales of emission allowances ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year absent express approval of the Commission. This PSA also provides a mechanism for mid-year rate adjustment by either the Commission or the Company (only if overcollection occurs) in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year's[3] PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual PSA Costs (fuel, purchased power and other allowable costs) and the recovery of those same cost elements through the combination of base rates and the Forward Component, and which provides for their recovery or refund during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek mid-year changes in the PSA Rate in cases where variances between the anticipated recovery of fuel and purchased power and other allowable costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery/refund, should the Commission deem such an adjustment to be appropriate or if the Company requests to make such a refund of an overcollection.
    b. The tracking of balances resulting from the application of the Transition Components in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before November 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before November 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

[3] Each February 1 through January 31 period shall constitute a PSA Year.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS's over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e., February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual November 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the current PSA Year). The APS filing shall use these balances to calculate the Historical Component for the coming PSA Year[4].

The November 30 filing's use of estimated balances for November through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1.

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any approved mid-year changes to the PSA rate. APS or Staff may request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection

[4] For example, the November 30, 2008 filing would include actual balances for February through October of 2008 and estimated balances for November 2008 through January 2009.

of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component. The Commission on its own motion may also change the PSA rate as described above.

Notwithstanding the preceding paragraph, APS may at any time during the PSA Year request to reduce the PSA through the Transition Component, which shall be deemed approved and become effective beginning with the first billing cycle of the month following the filing of such a request, provided APS files the request within the first 15 days of a month and Staff does not file opposition to the request.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before November 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year.

3. Calculation of the PSA Rate

The PSA Rate is the sum of the three components; *i.e.,* Forward Component, Historical Component and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA Rate by February 1, the proposed PSA Rate shall go into effect. However, the PSA Rate may not change from the prior year's PSA Rate by more than plus or minus $0.004 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA Rate shall be applicable to APS's retail electric rate schedules (with the exception of E-36 XL, AG-X, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA Rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. November 30 Filing

APS shall file the PSA Rate with all Component calculations for the PSA Year beginning on the next February 1, including all supporting data, with the Commission on or before November 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward

Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

b. Additional Filings

APS shall also file with the Commission any additional information that Staff determines it requires to verify the component calculations, account balances and any other matter pertinent to the PSA.

c. Review Process

The Commission Staff and interested parties shall have an opportunity to review the November 30 forecast, balances and supporting data on which the calculations of the three PSA components have been based. Any objections to the November 30 calculations shall be filed within 60 days of the APS filing. Before Storage Product Costs may be calculated in the PSA, APS will first seek approval. APS will request this approval by filing the third-party storage contract with the Commission at least 90 days before the contract becomes effective. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power and other allowable costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA year will be credited an amount equal to interest at a rate equal to the Company's authorized Return on Equity ("ROE") or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

Base Chemical Costs – An amount generally expressed as a rate per kWh, which reflects the non-fuel production costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The Base Chemical Costs are set at $0.000744 per kWh effective on TBD.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.038321 per kWh effective on TBD.

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on TBD.

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power as defined above, the Base Chemical Costs, and the Base Net Margins on the Sale of Emission Allowances.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS's base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS's over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue, plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest at year end. The balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mandated Carbon Emission Allowance Costs – The costs incurred in purchasing allowances to meet legal requirements, beginning in 2013, that electricity from resources which emit carbon must be accompanied by carbon emission allowances equal to the amount of carbon emitted in generating the electricity (recorded in FERC Account 509 – Allowances).

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load refers to the energy needed for customer load in the balancing authority area for which APS has a generation service obligation.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

PSA - The Power Supply Adjustment mechanism approved by the Commission.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus costs for environmental chemicals used in power production at fossil and nuclear production sites, approved storage product costs and the Net Margins on the Sales of Emission Allowances.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Storage Product Costs - All costs associated with third-party storage facilities, including rent, capacity, and lease payments for electricity storage facilities (e.g., batteries) that APS utilizes in the dispatch of generated or purchased electricity.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36 XL, AG-X, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. 78317.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS's electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration

Schedule 1 PSA Rate Calculation
Schedule 2 PSA Forward Component Rate Calculation
Schedule 3 PSA Year Forward Component Tracking Account
Schedule 4 PSA Historical Component Rate Calculation
Schedule 5 Historical Component Tracking Account
Schedule 6 PSA Transition Component Rate Calculation
Schedule 7 PSA Transition Tracking Account

8. Compliance Reports

APS shall provide monthly reports to Staff and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in APS's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs
    b. Margins on the sale of excess emission allowances
    c. Environmental chemical costs for fossil generation
    d. Customer sales in both MWh and thousands of dollars by customer class
    e. Number of customers by customer class
    f. A detailed listing of all items excluded from the PSA calculations
    g. A detailed listing of any adjustments to the adjustor reports
    h. Total off-system sales revenues
    i. System losses in MW and MWh
    j. Monthly maximum retail demand in MW

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:

1. Net generation, in MWh per month, and 12 months cumulatively
2. Average heat rate, both monthly and 12-month average
3. Equivalent forced-outage factor, both monthly and 12-month average
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description
5. Total fuel costs per month
6. The fuel cost per kWh per month

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):

1. The quantity purchased in MWh
2. The demand purchased in MW to the extent specified in the contract
3. The total cost for demand to the extent specified in the contract
4. The total cost of energy

C. Information on off-system sales shall include the following items:

1. An itemization of off-system sales margins per buyer
2. Details on negative off-system sales margins

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm or per MCF, total cost, supply basin and volume by contract

E. APS will also provide:

1. Monthly projections for the next 12-month period showing estimated over/under-collected amounts
2. A summary of unplanned outage costs by resource type
3. A summary of the net margins on the sale of emission allowances
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, costs for specified environmental chemicals that vary with power generated at fossil power plants, storage product costs, and the net margins on the sale of emission allowances and Mandated Carbon Emission Allowance Costs will also be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission (FERC) accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- 509 Allowances[6]

Additionally, broker fees recorded in FERC account 557 up to the amount included in the Base Fuel Cost, costs for environmental chemicals used in power production in FERC accounts 502 and 549, and the FERC account where applicable Storage Product Costs will be recorded are allowable accounts.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 (November 18, 2003) provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 XL and AG-X customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming

[6] Or any successor FERC account used to record the costs of purchasing carbon emission allowances.

power from the APS system so their power supply costs and kWh usage are excluded from the PSA.

Returning Customer Direct Access Charge
Plan of Administration

General Description

Section 2.6 of the May 17, 1999 Settlement Agreement ("Agreement") in Docket No. E-01345A-98-0473 allows Arizona Public Service Company ("APS") to recover the reasonable and prudent costs associated with compliance and implementation of the Electric Competition Rules beginning July 1, 2004. The Arizona Corporation Commission ("Commission") approved the collection of these costs in Decision No. 67744, Docket No. E-01345A-03-0437. Section 2.6(2) of the Agreement provides the opportunity to recover the costs of providing Standard Offer service to customers who have left an APS Standard Offer service or special contract rate for a competitive generation supplier and are returning to Standard Offer service. Customers that have been Direct Access customers since the origination of their APS service that request Standard Offer service are considered to be returning customers.

The Company may assign any of the above costs directly to the customer(s) who caused them via a Returning Customer Direct Access Charge ("RCDAC"). This will only be done when a customer, or an aggregated group of customers, with a monthly demand of three MW or greater returns to Standard Offer service and APS did not include their load in planned resource acquisitions. If APS is provided one year's advance notice of the customer's intent to return to Standard Offer service then they will not be assessed a RCDAC. APS may create a RCDAC in each individual case and require the customer(s) to enter into a service agreement that specifies the charge, its duration, and how it will be applied and collected. In situations where an aggregated group of customers wish to return, each customer from the group will be charged the same rate for the same duration and an agreement will be required from each customer.

Returning Customer Direct Access Charge

The RCDAC will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning customer(s). The costs associated with serving customers that are required to enter into RCDAC agreements will be kept separate from the retail power supply costs subject to recovery through the Power Supply Adjustment. The types of costs that will be used to develop the RCDAC are Incremental Power Supply, Transmission, Ancillary Services and Metering costs. These terms are defined as follows:

Incremental Power Supply - The costs of generation or purchased power supplied to the customer that is over the base rate power supply cost for their applicable rate schedule.

Transmission – The costs of delivering power across a utility system or to other utility systems.

Ancillary Service – The costs of services necessary to support the transmission of energy from the resources to the loads while maintaining reliable operation of the transmission provider's transmission system.

Metering – The costs of measuring the power used by the customer.

These costs will be amortized over an appropriate period to allow their timely recovery. In no event, however, will the RCDAC last longer than 12 months for any individual customer.

Resource Comparison Proxy
Plan of Administration

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1. General Description

This document describes the plan for administering the Resource Comparison Proxy purchase rate (RCP) approved for Arizona Public Service Company (APS or Company) in Arizona Corporation Commission (Commission) Decision No. 75859 (January 3, 2017), as modified by Decision No. 75932 (January 13, 2017) and implemented in Decision No. 76295 (August 18, 2017) and Decision No. 78317 (November 9, 2021) and Decision No. XXXXX (TBD). The RCP is the price at which the Company purchases Exported Energy from residential Customers with qualified on-site solar distributed generation facilities. This price is provided in Rate Rider RCP.

The RCP is a proxy for the avoided cost of providing electrical service that results when a distributed generator exports power to the grid. The RCP is calculated using: (i) a rolling historical five-year weighted average cost of grid-scale solar photovoltaic facilities that the Company owns or has rights to through a solar photovoltaic Purchased Power Agreement (PPA); and (ii) applicable Avoided Transmission Capacity Cost, Avoided Distribution Capacity Cost, and Line Losses.

2. Customer Billing

The Company will provide the Customer a monthly bill credit for the Export Energy based on the applicable RCP.

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; if the outstanding credits exceed $25 a check will automatically be issued; otherwise the bill credits will carry forward to the following year.

3. Resource Comparison Proxy Purchase Rate

The RCP will be determined as follows:

- An RCP will be determined for each tranche of new DG Customers, effective September 1 each year or as determined by the Commission, without proration. The RCP may not be reduced by more than 10% each year.

- Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before September 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

- Each Customer's initial RCP will be applicable for 10 years from the time of their interconnection.

- After each Customer's initial 10-year period the bill credit will be based on the purchase rate in effect at that time, and will change from year to year.

4. Definitions

Avoided Cost. In the context of this Plan of Administration, the additional cost APS would incur to acquire electric energy to serve its customers if electricity was not available from on-site distributed generation sources.

Avoided Distribution Capacity Cost. In the context of this Plan of Administration, the net cost of distribution grid equipment and facilities necessary to distribute electricity to APS customers if electricity from on-site distributed generation sources was not available.

Avoided Transmission Capacity Cost. In the context of this Plan of Administration, the additional cost of transmission grid equipment and facilities necessary to transmit electricity to APS customers if electricity from on-site distributed generation sources was not available.

Base Year. For the initial RCP calculation (effective September 1, 2017), the Company's most recent test year, calendar year ending December 31, 2015. Each subsequent annual calculation will use the immediately preceding calendar year as the Base Year. As an example, the RCP that will become effective with the first billing cycle of September 2018 will be calculated with the calendar year ending December 31, 2017 as the Base Year.

Customer(s). For purposes of this Plan of Administration, an APS Customer taking service under a Residential rate schedule.

Export(ed) Energy. Energy generated by an on-site interconnected solar photovoltaic distributed generation source that is greater than the Customer's electric load at any single point in time and flows into the Company's distribution grid.

Levelized Cost. For purposes of this Plan of Administration, the net present value of the overall cost of building and operating a grid-scale solar photovoltaic generating plant, or the net present value of the overall cost to APS of an executed solar photovoltaic PPA, over the economic life of the asset and converted to equal annual amounts.

Line Losses. Electric energy lost as it is transmitted from a supply source (i.e., an electric generation plant) to a delivery point (i.e., the Customer's residence or place of business).

Partial Requirements Service. Electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

Production Tax Credit. The income tax credit available in the State of Arizona for taxpayers that own a qualified renewable energy generator as defined in A.R.S. §43-1083.02 and §43-1164.03 that produces energy after December 31, 2010 and before January 1, 2021. The amount of Production Tax Credit available is limited by facility and by calendar year.

Revenue Requirement. For purposes of this Plan of Administration, the amount of revenue calculated to be recovered in rates for the APS-owned grid-scale solar facilities included in the RCP calculation. Revenue Requirement expenses include depreciation expense, income taxes, property taxes, deferred taxes and tax credits where appropriate, associated operation and maintenance expense, and an approved debt and equity return.

5. System Eligibility

A distributed generation facility must meet all of the following qualifications to be eligible for the RCP:

- Electricity must be generated using solar photovoltaic panels;
- The facility must be interconnected to the Company's distribution grid; and

- The generator must be on-site, installed behind the billing meter, and must serve the Customer's load.

Systems of any size are subject to the requirements found in the Arizona Administrative Code Distributed Generation Interconnection Requirements, APS's Interconnection Manual, Interconnection Agreement, and APS's Electric Service Requirements Manual.

SPECIAL CASES

Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the bill credits for export energy will be based on the annual RCP rate as it changes from year to year excepting where 10 or more years are remaining in the solar grandfathering status. In such instances, the customer will be eligible for a 10-year lock in the purchase rate in effect at the time of the switch.

Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this Plan of Administration, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.

Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

6. Calculation of Resource Comparison Proxy Purchase Rate

The RCP is calculated by developing a historical rolling five-year weighted average cost per kWh for all grid-scale renewable solar photovoltaic generating systems used by APS to serve its customers, both APS-owned facilities and facilities from which APS purchases power through an executed PPA. The calculation methodology is as follows:

The first RCP effective on September 1, 2017 is $0.12900/kWh, using 2015 as the Base Year inclusive of adjustments as provided for in Decision No. 75859. Subsequent RCPs derived from following the calculations in Steps 1 through 8 below will then be compared to the RCP in effect.

If the calculated RCP results in a reduction in the purchase rate from the previous RCP, any such reduction will be no greater than 10% of the previous RCP.

1. Determine appropriate five-year period. The RCP will be calculated using the 5-year period with the Base Year as the final year of the five. Only those grid-scale solar facilities with an in-service date within this 5-year period will be included in the annual RCP calculation.

If there are no grid-scale solar photovoltaic projects in any particular year of the rolling five-year period described above, the rolling 5-year average will be calculated without a project for that particular year. Calculating the RCP without a project for a particular year (i) is the product of the settlement approved in Decision No. 76295; (ii) is the product of compromise; and (iii) does not establish a precedent for how the RCP should be calculated.

2. Develop/update annual Revenue Requirement for each APS-owned facility. The Company will calculate revenue requirements for each grid-scale solar photovoltaic generation facility owned by the Company that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual designed output of the facility, including degradation, will be used for this calculation. This step provides an annual revenue requirement cost in dollars for each year of the facility's depreciable life.

3. Incorporate applicable Production Tax Credit. All expected available annual Production Tax Credit tax savings (in dollars) for the above APS facilities will be calculated based on expected annual energy production and subtracted from the annual facility cost derived in Step 2 above for each year.

4. Develop/update annual cost of power from each PPA facility. The Company will calculate an annual cost of purchased power for each facility from which APS purchases power under an executed agreement that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual cost for each of these facilities will be calculated separately for the contract life of each PPA using the contract price and the designed output, including degradation, of the facilities, including contractual escalation factors, as appropriate.

5. Calculate individual facility Levelized Cost. The Levelized Cost for each of the facilities will then be calculated using the data derived in Steps 2 through 4 above. The net present value discount rate used in the Levelized Cost calculations will be calculated using the approved after-tax weighted average cost of capital as determined in the Company's most recent rate case. The result of this calculation step will be a Levelized Cost per MWh for each of the facilities.

6. Calculate weighted Levelized Cost for each facility. The weighted Levelized Cost is calculated by multiplying the cost per MWh derived for each facility in Step 5 by the actual Base year energy production in MWh for each Step 5 facility. The result of this step is an annual weighted cost in dollars for each included facility.

7. Calculate weighted average Levelized Cost for all facilities. The annual weighted average Levelized Cost is determined by dividing the total annual weighted costs for all included facilities by the total Base Year energy production MWh. The result of this step is the rolling historical five-year weighted average Levelized Cost per MWh for grid-scale solar photovoltaic facilities on the APS system before any applicable adjustments.

8. Adjustments. An adjustment is then applied to the annual weighted average Levelized Cost per MWh for Avoided Transmission Capacity cost, Avoided Distribution Capacity cost, and Line Losses as required in Decision No. 75859. For purposes of this Plan of Administration, and subject to future Commission proceedings, the combined adjustment for these three values is set at $0.02/kWh as provided for in Decision No. 76295. This amount is negotiated, does not reflect an actual calculation of system conditions, and establishes no precedent for any future RCP calculations.

7. Procedural Timeline

The Company will provide Commission Staff and other intervening parties with its annual RCP calculation no later than May 1 each year. Interested parties will file comments to the Company's RCP calculation by June 1. Commission Staff will file its Report by July 15 and request that Staff's Report be considered in the August Open Meeting and be approved so that the new RCP calculation is effective on September 1.

8. Confidential Data

Portions of the data used to calculate APS's annual RCP are competitively/highly confidential and cannot be released to the public. Competitively/highly confidential information will be made reasonably accessible to parties so that they may determine that such data supports the RCP calculation and that the RCP calculation complies with Commission orders. Competitively/highly confidential information includes cost and production data for facilities from which APS purchases energy under a PPA agreement.

9. Schedules

Templates of the spreadsheet used to calculate the RCP are attached:

Schedule 1: Annual Resource Comparison Proxy Calculation Summary
Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost
Schedule 3: Individual Plant Annual Cost ($/MWh)
Schedule 4: Individual Plant Energy Production (MWh)
Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost ($000)
Schedule 6: Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits ($000)

Each of these schedules may contain competitively/highly confidential PPA data as indicated.

Renewable Energy Adjustment Charge
Plan of Administration

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1. General Description

This document describes the plan for administering Arizona Public Service Company's (APS or the Company) Adjustment Schedule REAC-1, Renewable Energy Adjustment Charge (Schedule REAC-1). As authorized for APS by the Arizona Corporation Commission (Commission) in Decision No. XXXXX (XXX X, XXX), Schedule REAC-1 provides for the recovery of, both, (1) approved renewable energy program costs in compliance with the Commission's Renewable Energy Standard Tariff (REST) rules and (2) approved capital carrying costs for qualified resources consistent with the APS IRP Action Plan.

2. Definitions

All-Source Request for Proposal (All-Source RFP) – A document issued by APS soliciting proposals from qualified parties in which all types of electric resources or energy storage projects that can meet all or part of the needs described in the RFP will be considered equally.

Allowable Costs – Schedule REAC-1 shall recover the following:

(1) The cost of renewable energy programs included in the Company's annual REST Plan, and approved by the Commission, that are not otherwise recovered in base rates or other recovery mechanism. Costs include, but are not limited to, program development, program implementation, purchased power costs not recovered through the Power Supply Adjustor, customer incentives, customer education and communication, technical assistance and training, marketing, advertising, administrative and general expense,
(2) The cost of monitoring and evaluation of the programs defined above,
(3) Funds approved by the Commission for Coal Community Transition or similar programs, and
(4) Capital Carrying Costs for Clean Energy Resources that are in service at the time Schedule REAC-1 rates are approved and are not yet being recovered in base rates or other recovery mechanism, including energy storage and excluding nuclear energy, and other relevant costs where such costs are not otherwise recoverable through an approved RES Implementation Plan.

Applicable Interest – Interest is applied on Balancing Account funds annually at the following rates: any over-collection existing at the time of the adjustor rate calculation will be credited an amount equal to interest at a rate equal to the Company's authorized return on equity (ROE) or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the time of the adjustor rate calculation will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Capital Carrying Costs – Capital carrying costs include (1) a return at the Company's Weighted Average Cost of Capital found by the Commission in the Company's most recent general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits associated with investments being recovered where appropriate and (6) associated operations and maintenance expenses.

Clean Energy Resources – Includes all non-carbon emitting APS-owned resources, including energy storage and excluding nuclear energy.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the Clean Energy Resource portion of the Schedule REAC-1 adjustor rate calculation as shown in Section 5 herein.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The ROE authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

Integrated Resource Planning Action Plan (IRP Action Plan) - The three-year plan required by the Commission's Integrated Resource Planning (IRP) Rules set forth in A.A.C. R14-2-703(H), which is based on the most recent IRP filed by APS and outlines the actions to be taken by the Company on future resource acquisitions.

Renewable Energy Standard and Tariff Rules (REST Rules) – The Commission's Rules, approved in Decision No. 69127 (November 14, 2006) and codified in A.A.C. R14-2-1801 et. seq., which provide for recovery of the costs incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.

Renewable Energy Standard Compliance Report (RES Compliance Report) – The report required

by A.A.C. R14-2-1812 et. seq., which is filed on April 1 of each year and describes APS's compliance with the requirements of the REST Rules for the prior calendar year.

Renewable Energy Standard Implementation Plan (RES Plan) – The report required by A.A.C. R14-2-1813 et. seq. as amended by this Plan of Administration, which is filed on November 1 of each year and describes how APS intends to comply with the REST Rules for the next calendar year. The REST Plan will include a description of the Clean Energy Resources to be included in the calculation of the Schedule REAC-1 adjustor rate and will include the calculations showing the derivation of the adjustor rate and the results of the Clean Energy Resources Earnings Test.

Service Schedule 6 – APS's Service Schedule 6, Interconnection Study Services and Fees for Non-FERC Generation Facilities, contains a schedule of fees for feasibility, system impact, and facilities studies for certain generators requesting interconnection to the Company's transmission and/or distribution system. Fees collected by APS for these studies are credited against the Balancing Account for this mechanism as described in Section 4.

3. Clean Energy Resource Eligibility

To be eligible for inclusion in the Schedule REAC-1 adjustor rate, Clean Energy Resources must be consistent with APS's IRP Action Plan and must be acquired through an All-Source RFP process. The All-Source RFP process will be in compliance with the Commission's Procurement Rules set forth in A.A.C. R14-2-705 and 706 and will include the use of an Independent Monitor.

If any eligible Clean Energy Resources generate revenue, such revenue will be included as a credit in the calculation of the Schedule REAC-1 adjustor rate.

Clean Energy Resources to be included in the Schedule REAC-1 adjustor rate will be discussed with stakeholders and interested parties in stakeholder meetings as shown in the Regulatory Timeline (Section 7). A summary of stakeholder meetings and a description of the included resources with relevant supporting documentation will be included in the annual REST Plan.

4. Balancing Account

Allowable Costs shall be recorded in a separately maintained Balancing Account. Revenues received by APS through Schedule REAC-1, as well as other relevant revenue (including, but not limited to, payments to APS under Service Schedule 6 and any revenue generated by eligible Clean Energy Resources), shall be credited to the Balancing Account.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in the Schedule REAC-1 adjustor rate in the subsequent calendar year.

5. Adjustor Components

Schedule REAC-1 shall consist of a monthly kilowatt-hour (kWh) charge applied equally to all Standard Offer and Direct Access service. The kilowatt-hour charge is subject to a monthly adjustor limit calculated for specific customer billing classes as determined by the Company and approved by the Commission.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in Schedule REAC-1 in the subsequent calendar year.

6. Determination of the Adjustor Rate and Limits for Schedule REAC-1

In accordance with Commission Decision No. 73183, customers who receive an incentive under the Renewable Energy Standard and install their system after July 1, 2012 will pay an applicable monthly limit.

Schedule REAC-1 shall be revised annually to recover Allowable Costs as determined by the Commission through the review and approval process outlined in Section 7 below. The Schedule REAC-1 kWh rate shall be designed using projected billing determinants for the calendar year in which the adjustor rate is expected to become effective. The billing determinants shall include total retail kWh subject to Schedule REAC-1 and the number of customers and associated kWh that are billed under each adjustor limit.

7. Review and Approval

Schedule REAC-1 shall be filed for the upcoming calendar year as part of the Company's REST Plan, which is filed on November 1st each year as approved in Decision No. XXXXX. Supporting information for the calculation of rates shall be provided for Staff and interested parties to review.

Prior to filing each year, the Company will review the RES Implementation Plan, including new programs and investments, with Commission Staff and stakeholders. Commission Staff will review the information, along with input and comments from interested parties, and will issue a report and proposed order for Commission approval.

Once approved by the Commission, the Schedule REAC-1 adjustor rate will be effective each year beginning with billing cycle 1 of the October revenue month or as otherwise ordered by the Commission and will not be prorated.

Regulatory Timeline	
Prefile Stakeholder Meeting	Early September
Prefile Stakeholder Meeting if desired	Early October
File RES Implementation Plan	November 1
Stakeholder Meeting	Mid-December
Staff Report Target	Mid-August
Open Meeting Target	September
Rate Implementation	October 1

8. Earnings Test

Any requested increase in the Schedule REAC-1 adjustment mechanism related to Clean Energy Resources will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold.

If the results of the Earnings Test are higher than the Earnings Test Threshold, the Clean Energy Resources capital carrying cost recovered through Schedule REAC-1 will be limited to the

amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule REAC-1 in a future year.

9. Schedules

APS's annual REST Plan will include attachments and schedules detailing all calculations that develop the proposed REAC-1 adjustor rates.

Schedules outlining the proposed cost and expected generation from RES-related programs and facilities are based on the templates developed by the REST Format Working Group as required in Decision No. 72737 and approved by Staff.

The REST Plan will include the following Schedules that outline the development of the earnings test as attached to this document:

Earnings Test Schedule 1: Annual Earnings Test
Earnings Test Schedule 2: Capital Structure

APS will continue to file the annual RES Compliance Report on April 1 of each year as required by the REST Rules.

Transmission Cost Adjustment
Plan of Administration

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1. General Description

The purpose of the Transmission Cost Adjustment (TCA) is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission (FERC) and at the same time as new transmission rates become effective for Arizona Public Service (APS or Company) wholesale customers. APS shall file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC Informational Filing of its Annual Update of transmission service rates pursuant to its Open Access Transmission Tariff (OATT). This notice shall be filed with the Commission at the same time that APS makes its FERC filing.

The TCA applies to APS's Retail Electric Rate Schedules. For Standard Offer customers, the TCA is applied to the bill as a monthly kWh charge for Residential Service Customers and General Service Customers less than or equal to 20 kW. For all other Standard Offer customers, the TCA is applied to the bill as a monthly kW charge. The charge and modifications to it will take effect in billing cycle 1 of the June revenue month without proration.

APS's Network Integration Transmission Service (NITS) is calculated and filed annually with FERC in accordance with APS's formula rate. The formula rate calculation is specified within the Company's OATT as filed and approved by FERC.

2. Calculations

The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC Informational Filing of its Annual Update of transmission service. NITS rates as determined for the following classes include:

Residential Service Customers
General Service Customers less than or equal to 20 kW
General Service Customers over 20 kW and less than 3 MW
General Service Customers equal to and greater than 3 MW

In addition to NITS, APS charges retail customers for other transmission services in accordance with its OATT. These additional ancillary services include:

Schedule 1 - Scheduling, System Control and Dispatch Service

Schedule 3 - Regulation and Frequency Response Service
Schedule 4 - Energy Imbalance Service
Schedule 5 - Operating Reserve - Spinning Reserve Service
Schedule 6 - Operating Reserve – Supplemental Reserve Service

APS's NITS rates will change annually, where ancillary service charges will change only through a separate filing when made by the Company to FERC.

The total APS OATT rate is the sum of the rates for providing these services. The revenue requirement resulting from the FERC APS OATT rate is collected by APS from its retail customers, partly in base rates and the remaining through the TCA rate.

3. TCA Balancing Account

APS will maintain accounting records that accumulate the difference in revenues anticipated to be recovered by the TCA, as compared to the actual revenues received by the Company through the TCA during the recovery period (June through May). The difference will be recorded to the TCA Balancing Account each month and will be provided annually in Attachment C of the filing. In the event the actual TCA revenues for the recovery period (June through the last billing cycle of May) are more or less than the anticipated revenues for that same period, the over or under collection will be subtracted from or added to the TCA balancing account calculation for the subsequent period.

4. Filing and Procedural Deadlines

APS will file the calculated TCA rates with the Commission each year no later than May 15th, in the form of Attachments A through H as attached to this document and described in Section 5. *Compliance Reports*.

The Commission Staff and interested parties shall have the opportunity to review APS's FERC Informational Filing of its Annual Update of transmission service rates pursuant to the APS OATT Attachment H-2, Formula Rate Implementation Protocols. The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC filing. The new TCA rates proposed by APS will go into effect with the first billing cycle in June (without proration), unless Staff requests Commission review or otherwise ordered by the Commission, and will remain in effect for the following 12-month period.

5. Compliance Reports

APS will provide an annual report to Staff detailing all calculations related to the calculated TCA rates. The reports will include the following Attachments A through H as attached to this document:

Attachment A:	Non-redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment B:	Redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment C:	Numerical inputs used to develop the new TCA-1 rates
Attachment D:	Estimated monthly bill impacts of the new TCA-1 rates

Attachment E:	Table illustrating the percentage demand of each of the classes for the 20XX OATT and 20XX OATT as filed with FERC
Attachment F:	Table illustrating the transmission cost embedded in base rates, the current and proposed TCA rates, and the differences in the current and new rates
Attachment G:	Actual and estimated transmission additions, dollars and estimated O&M for calendar years 20XX through 20XX (1 year actual and 2 years forecast)
Attachment H:	APS's Annual Update of transmission service rates pursuant to the APS OATT as filed with FERC

Tax Expense Adjustment Mechanism
Plan of Administration

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1. General Description

This document describes the plan for administering the Federal and State Income Tax Expense Adjustment Mechanism (TEAM) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on November 9, 2021 in Decision No. 78317 and Decision No XXXX on XXXXX. The TEAM enables the pass-through of income tax effects that materially impact the Company's Test Year revenue requirements[1] to customers resulting from federal or state income tax legislation. The TEAM will be calculated annually on a prospective basis.

2. Definitions

Annual Tax Expense Adjustment – The Annual Tax Expense Adjustment represents the amount to be passed through to jurisdictional retail customers in the subsequent twelve-month period and is applied to customer bills via a $ per kWh adjustment.

Base Revenue Requirements Change – The change in the Company's Base Revenue Requirements as a result of any Federal and/or State income tax reform legislation will be measured as the change in:

a. The Federal and/or State Income Tax Rate-Test Year as compared to the Federal and/or State Income Tax Rate-Revised as applied to the Company's Adjusted Test Year in Decision No. XXXXX;
b. Annual amortization of any resulting deficient or excess deferred income tax regulatory account compared to the Company's Adjusted Test Year in Decision No.XXXXX; and
c. New permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted Test Year in Decision No. XXXXX.

[1] "Material impacts" is defined as changing APS's revenue requirement by more than $5 million.

Federal Income Tax Rate-Revised – The Federal marginal corporate income tax rate as set forth in relevant legislation.

Federal Income Tax Rate-Test Year – The Federal marginal corporate income tax rate of 21% in effect and utilized in the revenue requirements as approved by the Commission in Decision No. XXXXX.

Forecasted Retail kWh Sales – The forecasted calendar year energy (kWh) sales served under applicable ACC jurisdictional retail electric rate schedules. A true-up reconciliation of the forecasted data will be completed in the following year through the Balancing Account.

Protected Deficient or Excess ADIT – Changes in net Accumulated Deferred Income Taxes (ADIT) due to the Federal Income Tax Rate-Revised or State Income Tax Rate – Revised which must be passed through to Customers under specific IRS or State requirements (such as differences between regulatory depreciation calculations and tax depreciation calculations).

State Income Tax Rate-Revised – The State marginal corporate income tax rate (net of Federal tax benefits) as set forth in relevant legislation.

State Income Tax Rate-Test Year – The State marginal corporate income tax rate (net of Federal tax benefits) of 3.75% in effect and utilized in the revenue requirements as approved by the Commission in Decision No. XXXXX.

Unprotected Deficient or Excess ADIT – All changes in net ADIT due to the Federal Income Tax Rate-Revised or State Income Tax Rate - Revised that are not Protected Deficient or Excess ADIT. These changes may be passed through to Customers as determined by the Commission.

3. Calculation of TEAM

The Annual Tax Expense Adjustment is calculated annually and represents the amount to be passed through to jurisdictional retail customers. The adjustment is calculated based on the Company's Base Revenue Requirements Change as defined above.

The Annual Tax Expense Adjustment may include up to three separate components:

> Phase I Component. The Phase I component represents the Base Revenue Requirements Change due to the difference between the Federal and/or State Income Tax Rate-Revised and the Federal Income Tax Rate-Test Year.

Phase II Component. The Phase II component represents the Base Revenue Requirements Change due to Unprotected Deficient or Excess ADIT as defined above which was recorded on the Company's balance sheet as of the effective date of relevant Federal or State tax legislation

Phase III Component. The Phase III Component represents the Base Revenue Requirements Change due to Protected Deficient or Excess ADIT as defined above. Additionally, the Phase III Component will also address adjustments necessary to both Protected Deficient or Excess ADIT and Unprotected Deficient or Excess ADIT to reflect differences between tax positions reported in the Company's regulated books of account as of the effective date of relevant Federal tax legislation and positions which will be taken on the Company's Federal tax return for the same time frame.

The TEAM $ per kWh rate is calculated by dividing the Annual Tax Expense Adjustment by the Forecasted Retail kWh Sales. For billing purposes, the TEAM Phase I, Phase II, and Phase III Components will be combined.

As determined in Decision No. 76601 (March 5, 2018), Customers served under the Company's Rate Rider AG-X (Alternative Generation) will receive 75.64% of the TEAM $ per kWh rate as calculated above. Customers served under the Company's Experimental High Load Factor Rate Schedules HLF-1, HLF-2, and HLF-3 will receive 86.84% of the TEAM $ per kWh rate.

4. TEAM Balancing Account

APS will maintain accounting records that accumulate the difference between each Component, as necessary, of the calculated Annual Tax Expense Adjustment as compared to the actual amounts applied to customers' total bills through the total TEAM $ per kWh adjustment during the prior calendar year. Additionally, as a result of utilizing Forecasted Retail kWh Sales, the balancing account will contain a true-up component in which estimated balances will be replaced with actual balances for the prior year filing.

Differences will be recorded to the TEAM Balancing Account each month and will accrue interest at the Company's applicable cost of short-term debt.

5. Compliance Reports

Each year until the TEAM is terminated, on or before March 1 APS will provide a report to Staff and the Residential Utility Consumer Office showing the status of the TEAM Balancing Account described in Section 4 above.

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all service schedules and rate schedules including but not limited to rider and adjustor schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. **Application for Service**

Before supplying service, APS will verify the identity of Applicant. Applicants may be required to appear at the Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and the Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 **Grounds for Refusal of Service** – APS may refuse service if any of the following conditions exist:

(A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to the Company.

(B) A condition exists that, in the Company's judgment, is unsafe or hazardous.

(C) The Applicant has failed to meet the Company's security-deposit requirements outlined in Section 3.

(D) The Applicant is known to be in violation of a Company Tariff.

(E) The Applicant fails to furnish the funds, service, equipment, rights-of-way or easements required to serve the Applicant that APS has specified as a condition for providing service.

(F) The Applicant falsifies his or her identity for the purpose of obtaining service.

(G) Service is already being provided at the address for which the Applicant is requesting service.

(H) A prior Customer, who will reside at or benefit from service at the Applicant's Premises, owes APS a delinquent bill for the same class of service from the same or a prior service address.

(I) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

2. **Service Establishment**

A Service Establishment Charge of $0.00 for residential or $0.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month. All service establishment requests are subject to availability; there is no guarantee that the Company will have the ability to provide service establishment, re-establishment, or reconnection of service on same-day requests or requests made outside of regular business hours. For situations where the Company is unable to complete same-day or after-hours requests, service establishment will be scheduled for the next available business day.

2.1 **Multiple Connects –** If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service Establishment Charge once for every two Delivery Points.

2.2 **After-hours Connect –** The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $0.00 for residential with standard metering, $0.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 **Same-Day Connect –** The Customer must also pay a same-day connect charge of $0.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by the Company, waive the same-day fee.

2.4 **Non-Standard Service Request –** The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when the Customer requests

services that do not meet the definition of Service Establishment as defined in A.A.C. R14-2-203.D.3 and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives the Company uses to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 **Waiving of Service Establishment Charge** – The Company may waive the Service Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with the Company.

3. **Establishing Credit, Security Deposits and other forms of Credit Assurance**
When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to provide a security deposit to secure payment of bills for service.

3.1 **Residential Establishment of Credit** – APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

(A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.

(B) The Company receives an acceptable credit rating, as determined by the Company, for the Applicant from a credit-rating agency used by the Company.

(C) The Applicant can produce a letter regarding verification of credit from an electric utility that provided service of a comparable nature to the Applicant within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.

(D) If, in lieu of a security deposit, the Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.

3.2 **Nonresidential Establishment of Credit –** All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

(A) The Applicant had service of a comparable nature with the Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.

(B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 **General Deposits Guidelines –** If a security deposit is required, a separate deposit may be required for each service location.

(A) A Customer's security deposit will not preclude the Company from terminating an agreement for service or suspending service if the Customer fails to meet service-agreement obligations.

(B) The Company may choose to accept less than the full deposit required at the time service is established based on the Customer's financial condition.

(C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, the Company may require the Customer to establish or reestablish a security deposit.

3.4 **Residential Security Deposits –** Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by the Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 **Nonresidential Security Deposits –** Nonresidential security deposits will not exceed two and one-half times the Customer's maximum monthly billing as estimated by the Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by the Company based on the results of using a credit-scoring worksheet. The Company

will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 **Deposit Interest –** Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 **Deposit Refunds –** If the Customer terminates all service with the Company, the Customer's security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days of the Customer's final bill due date.

3.8 **Residential security deposits** or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

(A) **Nonresidential security deposits** and noncash deposits on file with the Company will be reviewed after 24 months of service and will be returned if:

(1) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(2) The Customer's financial condition does not warrant an extension of the security deposit.

4. **Rates**

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 **Rate Selection –** APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, the Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 **Rate Information –** APS will make available, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in the Company's Tariff affecting those Customers.

4.3 **Optional Rates** – Optional rate schedules are available for certain classes of service. After establishing service, a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. For non-residential customers, no further rate schedule changes may be made within the succeeding 12-month period If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

4.4 The Company may, at its discretion, place a Customer on an available rate schedule (consistent with the existing meter's ability to measure service) while the Company seeks satisfactory and unassisted access to the Company's equipment if the Customer refuses to allow meter access. Please also see 7.3(E).

5. **Billing**

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at the Company's option.

5.1 **Payment of Bills** – The Customer is responsible for paying bills until service is ordered discontinued and the Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services are involved, until the Company has had reasonable time to process the disconnect request.

5.2 **Failure to Receive Bills or Notices** (including notices of disconnection) which have been properly placed in the United States mail to the Customer's last address on file or sent by or through alternative methods of communications, such as electronic mail to the Customer's last email address on file, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the Customer of their obligations.

5.3 **Incentive for Electronic Payments** – A monthly incentive of $0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

5.4 **Billing Errors** – When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.

5.5 **Corrected Charges for Overbilling –** Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by the Company.

5.6 **Corrected Charges for Underbilling –** Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and will not be limited to three or six months.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by the Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with the Customer to establish a payment plan that is acceptable to the Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

5.7 The Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. **Collection Policy**

The following collection policies apply to all Customer accounts:

6.1 **Delinquent Bills –** All bills rendered by the Company are due and payable no later than 21 calendar days from the billing date. Any payment not received within this time frame is delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of the Company's termination procedure. The Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.

6.2 **Late Charges –** All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 **Transfer of Outstanding Bills –** If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to the Company, the Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, the Company has the right to collect the full amount owed from any one of the Customers.

6.4 **Dishonored Payments –** If the Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, the Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to the Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The Company will waive the $15.00 Dishonored Payment fee if the Customer has not, in the previous 12 months, had a dishonored payment.

(C) The tender of a dishonored payment does not relieve the Customer of the obligation to pay the Company under the original terms of the bill, nor does it defer the Company's right to terminate the Customer's service for nonpayment of bill(s).

(D) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, the Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 **Collection Agency Referrals –** All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, the Customer may be responsible for the associated collection-agency fees incurred.

7. **Termination of Service**

7.1 To avoid termination of service: The Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to the Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company. APS may also require payment of Same-Day and After-Hours charges prior to restoring service.

7.3 **Termination of Service with Notice** – APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if the Company has met the notice requirements established by the Arizona Corporation Commission:

(A) The Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.

(B) The Customer's failure to pay a Delinquent Bill for services provided by Company.

(C) The Customer's breach of a written contract for service.

(D) The Customer's failure to comply with the Company's deposit requirements.

(E) The Customer's failure to provide the Company with satisfactory and unassisted access to the Company's equipment.

(F) When necessary to comply with an order of any governmental agency having jurisdiction.

(G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the Premises.

(H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.

(I) The Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

(J) When the Company learns of the unauthorized resale of utility equipment or services by the Customer.

7.4 **Termination of Service Without Notice** – Notwithstanding subsections 7.1, 7.3, 7.5, and 7.7, the Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

(A) An obvious hazard to the safety or health of the Customer, the general population or the utility's personnel or facilities;

(B) The Company has evidence of Meter Tampering or fraud related to the Customer or the service address; or

(C) The Customer fails to comply with the curtailment procedures imposed by the Company during a supply shortage.

7.5 **Termination of Service for Dishonored Payment –** Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, certified funds, or cashier's check. If Customer has already received a final notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

(A) When the Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.

(B) When the Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 **Termination Charges – The** Company will require payment of a Field Call Charge of $0.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

7.7 **Residential Service Termination Process**

(A) Except as provided in subsection 7.4, the Company shall not disconnect residential service to a Customer:

(1) From June 1 through October 15;

(2) If the Customer has paid at least half of the Customer's Delinquent Bill balance within the last 25 days;

(3) Due to a Customer's failure to pay the disputed portion of a bill if the Customer has complied with A.A.C. Rl4-2-212(B);

(4) If the Customer's Delinquent Bill balance is less than or equal to $300.00; or

(5) If the Customer can establish, on an annual basis, through medical documentation that, in the opinion of a licensed medical practitioner:

a. Termination would be especially dangerous to the health of the Customer or a permanent resident residing at the Customer's service address; or
b. If life support equipment used in the home is dependent on utility service for operation of such apparatus.

(B) The Company shall provide notice of the following, using the Customer's preferred method of communication on file, to a Customer whose service would be disconnected except for subsection 7.7(A)(1):
(1) The Customer would have been disconnected if not for subsection 7.7(A)(1);
(2) The reason the Company is not permitted to disconnect service;
(3) The Customer's continued financial responsibility for the charges accruing to the account for energy used;
(4) The potential actions the Customer may take to prevent the disconnection of service when subsection 7.7(A)(1) no longer applies; and
(5) The requirement to enter into a payment plan as specified in subsection (D).

(C) The Company shall not disconnect residential service unless the Company's office is open to the public on the day of disconnection and the day following the day of disconnection.

(D) A Customer with a Delinquent Bill balance of over $75 whose service disconnection was prevented by subsection 7.7(A)(1) shall be automatically placed on a six-month deferred payment arrangement prior to beginning the service termination process once the no disconnect period set forth in subsection 7.7(A)(1) has ended. The Company shall not impose any late fees or interest on any past due amounts that accrued during the no disconnect period.

(E) If a residential Customer is delinquent on an account and has a cash deposit with the Company, the Company shall use the deposit to pay the delinquent amount before disconnecting service, then allow the Customer time to repay the deposit in installments over a period of six months.

8. **Metering & Metering Equipment**

8.1 **Standard Metering –** The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All Customers will be served using the Company's standard metering equipment unless:

(A) The Customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) The Customer meets all eligibility requirements for non-standard metering and requests non-standard metering.

8.2 **Non-Standard Metering –** The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to Customers who select a non-standard meter.

8.3 **Non-Standard Metering Eligibility –** Only residential Customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or Customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 **Non-Standard Metering Charges** – The following charges will apply when a Customer requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for Customers with existing AMI meter.

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see Section 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 **Discontinuation of Non-Standard Metering –** The Company may replace a non-standard meter with a standard meter, without notifying the Customer prior to replacement, under any of the following conditions:

(A) The Company employees observe or have evidence of a safety hazard to employees, Customers, or the Company's or Customer property.

(B) The Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) The Company has evidence of unauthorized resale of electricity.

(D) The Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to the Company equipment, and physical threats such as weapons or dogs.

All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 **Measuring Customer Service** – All energy sold to the Customer by the Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by the Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 **Meter Rereads** – When requested by a Customer, APS will reread the Customer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 **Meter Testing** – APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon a Customer's request. If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 **Meter Test Charge** – If the Meter is found to be within the plus or minus 3% limit, the Company may charge the Customer $44.00 plus applicable adjustments for a Customer-requested Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

(A) The Company will waive the Meter Test Charge if the Customer has not, within the previous 12 months, requested a meter test that was found to be within the plus or minus 3% limit.

8.10 **Meter Tampering** – If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion, will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by the Company.

9. **Service Installations & Metering** – The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of

service, or total service cannot be measured through one Meter according to the Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

9.1 **Customer Equipment –** The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for the Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by the Company. In circumstances where a clearance is not required by law, the Company may require the Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to the Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining the Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

9.2 **Special Meter-Reading Device –** Where a Customer requests, and the Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

9.3 **Totalized Metering and Billing –** The Company normally meters and bills each site separately. But, at the Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at the Company's option, be considered a single site as specified in the Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

9.4 **Service Connections –** The Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

(A) For overhead service, the Point of Delivery is where the Company's service conductors terminate at the Customer's weatherhead or bus rider.

(B) For underground service, the Point of Delivery is where the Company's service conductors terminate in the Customer's or development's service equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing the Company's underground service conductors.

(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and the Company, only authorized employees or agents of the Company are permitted to make and energize the connection between the Company's service wires and the Customer's service entrance conductors. APS employees must carry the Company-issued identification that they will show on request.

10. **Customer Obligations**

10.1 **Load Characteristics –** The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customers must meet power factor requirements as specified in the applicable rate schedules.

10.2 **Easements –** All suitable Easements or rights-of-way required by the Company for any portion used to serve Customer(s), which are either on sites owned, leased, or otherwise controlled by the Customer(s) or developer(s), or other property required for the Company's use, will be furnished in the Company's name by the Customer(s) without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All Easements or rights-of-way granted to, or obtained on behalf of, the Company will contain terms and conditions that are acceptable to the Company. Notwithstanding the terms of a written Easement or right-of-way, when the Company discovers that a Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or adjacent to Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with the Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, the Company will notify the Customer or the Customer's agent and may take whatever actions are necessary to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. The Company will notify the Customer in writing before taking such action.

10.3 **Access for Repair, Maintenance and Service Restoration –** The Company's authorized agents must have satisfactory unassisted, 24-hour-a-day, seven days a week access to the Company's equipment located on the Customer's sites for the purpose of repair, maintenance, and service-restoration work that the Company may need to perform.

10.4 **Access for Install, Inspect, Read, or Remove –** The Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 **Trip Charge –** A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

(A) The Company will waive the Trip Charge if, within the last 12 months, there have not been any instances where an authorized Company representative traveled to a site and was unable to complete the Customer's service request because of lack of access to the Point of Delivery.

10.6 **Six Months No Access –** If the Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then the Company has sufficient cause to terminate service or deny any rate options where, in the Company's opinion, access is required.

10.7 **Remedies –** The remedy for unassisted access will be at APS's discretion and may include the installation by the Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for the Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

11. **Company Obligations**

11.1 **Customer-Specific Information** – Customer-specific information will not be released without the Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with the Company if the goods or services will help the Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to the Company.

11.2 **Service Voltage** – The Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208.F. The Company may deliver service for special applications at higher voltages, with prior approval from the Company's Engineering Department and in accordance with the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. **Limitations on Liability of Company**

12.1 **General Liability**

(A) The Company will not be responsible for any third-party claims against the Company that arise from a Customer's use of the Company's electric services or the Company's provision of electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

(B) A Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

(C) Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to a Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of

the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

(D) In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue, loss of current or prospective business opportunities, lost profits and lost rent) of any kind whatsoever regardless of the cause or foreseeability thereof.

(E) The Company will not be responsible in any occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

12.2 **Service Interruptions**

(A) The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 12.3(A) or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment or to eliminate the possibility of damage to the Company's property or to the person or property of others.

(B) Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this interruption or limitation will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

(C) The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

(D) In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(E) The use of electric energy upon the Customer's Premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

12.3 **Force Majeure**

(A) Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

(1) flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;
(2) accident or explosion;
(3) war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;
(4) acts of God;
(5) interference of civil and/or military authorities;
(6) strikes, lockouts or other labor difficulties;
(7) vandalism, sabotage or malicious mischief;
(8) usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;
(9) breakage, failure, or accidents to equipment or facilities; or
(10) lack, limitation or loss of electrical or fuel supply; or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

(B) A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

(C) Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

13. **Successors and Assigns –** Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and the Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by the Company.

14. **Warranty –** There are no understanding, agreements, representations, or warranties, expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by the Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of the Company in connection with sales and deliveries.

15. **Direct Access Service –** *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*
    15.1 **Direct Access Service Request (DASR) –** A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (ESP submitting the DASR each time the Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.
    15.2 **Direct Access Service –** Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.
    (A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.
    (B) If a Customer returning to Standard Offer Service, in accordance with the rules, regulations and orders of the Commission, was not given the required

notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer Service.

(C) Unpaid charges incurred before the Customer selects Direct Access Service will not delay the Customer's request for Direct Access Service. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to the Company under the Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, the Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where the Company is the MRSP, the Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of the Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 **Direct Access Deposits –** If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under the Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that the Company is providing bundled electric service.

15.4 **Direct Access and Company Equipment**

(A) **Meters –** A Meter Service Provider (MSP) or its authorized agents may remove the Company's metering equipment under the Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to the Company or returned damaged will result in charge(s) to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) **Lock-rings –** The Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and

conditions of the Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If the Company must replace 10% of the issued keys within any 12-month period because of loss by the MSP's agent, the Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock-ring keys must be returned to the Company within five working days if the MSP or its authorized agents are:

(1) No longer permitted to remove Company Meters under the conditions of the Company's Schedule 10;
(2) No longer authorized by the Arizona Corporation Commission to provide services; ort
(3) The ESP Agreement has been terminated.

(C) **Site Meetings –** If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. The Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If the Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Date is the date the statement was created either in electronic or paper form as shown on the bill regardless of the postmark, mailing, or electronic transmittal date.

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30-day intervals. [A.A.C. R14-2-201-(5)]

Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company Holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, Christmas Eve, Christmas Day, and New Year's Eve.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (22 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(13)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on a Customer's property. [A.A.C. R-14-2-201-(14)]

Easement means the right to use land owned by another party by grant or as allowed by law. An easement gives the Company the right to have Company lines or facilities on property not owned by the Company. This allows the Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity and for other purposes. The owner may continue to use the land in the easement as provided by a written easement or by law.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and the Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not apply, and service will automatically be transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with the Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(27)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(29)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from the Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(30)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(31)]

On-site means on a single Premises served by the Company's facilities.

Premises means all of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by alleys, canals, streets, railways, or other public rights-of-way.

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(35)]

Working Day means a weekday (during normal business hours) that is not designated as a Company holiday.

Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$0.00	2
Nonresidential Service Establishment Charge	$0.00	2
After hours Charge – Residential Standard Metering	$0.00	2.2
After hours Charge – Residential Non-Standard Metering	$0.00	2.2
After hours Charge – Nonresidential	$164.00	2.2
Same Day Connect Charge	$0.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
Electronically Transmitted Payment Discount	($0.48)	5.3
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$0.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering – Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9
Trip Charge – Residential	$22.00	10.5
Trip Charge – Nonresidential	$26.00	10.5

General Description

The following Terms and Conditions and any changes authorized by law will apply to the purchase of electric energy under the established rate(s) applicable at time of purchase. These Terms and Conditions will be considered a part of all Arizona Public Service Company's (APS or Company) rate schedules for purchases except where specifically changed by written agreement.

1. Definitions

1.1 Point of Interconnection - The point where Company's service conductors are connected to Customer's service conductors.

1.2 Qualifying Facility (QF) - Any cogeneration or small power production facility that meets the criteria for size, fuel use, efficiency, and ownership as stated in 18 C.F.R., Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

1.3 Purchase Agreement - The agreement between Customer and Company detailing the provisions for the purchase of electric energy by Company from Customer's QF, and the sale, if any, of power by Company to Customer.

1.4 Cogeneration Facility - Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

1.5 Small Power Production Facility - A facility that uses primarily biomass, waste, or renewable resources; including, but not limited to, wind, solar, and water to produce electric power.

2. Customer Obligations

2.1 Customer agrees not to begin interconnected operation of its QF with Company's system until the installation has been inspected by an authorized Company representative and final written approval to begin interconnected operation is received from Company. Customer will give reasonable notice to Company when initial startup is to begin. Company has the right to have a representative present during initial energizing and testing of Customer's system.

2.2 Customer will own and be fully responsible for the costs of designing, installing, operating and maintaining the following:
(A) The QF in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.
(B) Control and protective devices to protect its facilities from abnormal operating conditions such as, but not limited to, electrical overloading, abnormal voltages,

and fault currents. Such protective devices will promptly disconnect the QF from Company's system in the event of a power outage on Company's system.

(C) A gang operated load break disconnect switch, capable of being locked in a visibly open position that will completely isolate the QF from Company's system. Such disconnect switch will be installed in a place easily accessible to Company's personnel. Company will have the right to lock open the disconnect switch without notice to Customer when interconnected operation of the QF with Company's system could adversely affect Company's system or endanger life or property.

(D) Interconnection facilities on Customer's premises as may be required to deliver power from Customer's QF to Company's system at the agreed Point of Interconnection.

2.3 Electric sales to Company must be single or three phase, 60 Hertz, at one standard voltage (12,500; 2400/4160; 277/480; 120/240 or 120/208 volts as may be selected by Customer subject to availability at the premises). Customer's facilities will also maintain a minimum 90% leading to 90% lagging power factor as measured at the Point of Interconnection.

2.4 The electrical output of Customer's QF will not contain harmonic content which may cause disturbances on, or damage to, Company's electrical system, or other party's systems, such as, but not limited to communication systems.

2.5 Customer will operate and maintain the QF in accordance with those practices and methods, as they are changed from time-to-time, that are commonly used in prudent engineering and electric utility operations and will operate the QF lawfully and in a safe, dependable, and efficient manner.

2.6 Prior to actual installation, Customer will submit to Company for review and advance written approval, written equipment specifications and detailed plans for the installation and operations of its QF, interconnection facilities, control and protective devices and facilities to accommodate Company's meter(s). After Company's approval Customer will not change or modify equipment specifications, plans, control and protective devices, metering and in general the QF's system configuration. If Customer desires to make changes or modifications, Customer will resubmit to Company plans describing desired changes or modifications. No such change or modification may be made without the prior written approval of Company.

2.7 In the event it is necessary for Company to install interconnection facilities on its system (including, but not limited to control or protective devices, or any other facilities) in order to receive or continue to receive or to deliver electric power under the terms of the Purchase Agreement, Company will inform Customer of the cost in advance of incurring the costs of such facilities and Customer will reimburse

Company for the costs incurred by Company in connection with such facilities to the extent that said costs exceed those normally incurred by Company with respect to those Customers which it serves who do not have self generation facilities.

2.8 If Customer utilizes the Company's system to facilitate start-up of its QF, the voltage flicker level will not exceed Company standards.

3. Metering Provisions

3.1 Customer will provide and install at no expense to Company, and in accordance with Company's service standards, meter sockets and metering cabinets in a suitable location to be determined by Company's representatives.

3.2 Company will furnish, own, install and maintain all meters that register the sales of power to, and the purchases of energy from Customer. The responsibility for the costs of providing and maintaining the required meters will be as outlined in the applicable Rate for Purchase, or as specified in the Purchase Agreement.

3.3 The readings of all said meters will be conclusive as to the amount of electric power and energy supplied to the QF and/or purchased by Company unless, upon test, the meters are found to be in error by more than 3%. The expense of any meter test requested by Customer will be borne by Customer unless such test shows the meter(s) to be in error by more than 3%.

4. Mutual Understandings

4.1 Company will be allowed to install on Customer's premises any instrumentation equipment for research purposes. Such equipment will be owned, furnished, installed and maintained by Company.

4.2 Company's approvals given pursuant to the Purchase Agreement will not be construed as any warranty or representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective devices or the design, construction, installation or operation thereof.

4.3 Company (including its employees, agents, and representatives) will have the right to enter Customer's premises at all reasonable times to (a) inspect Customer's QF, protective devices and to read or test instrumentation equipment that Company may install, provided that as reasonably possible, notice is given to Customer prior to entering its premises; (b) maintain Company equipment relative to the purchase of electric energy from Customer; (c) read or test the meters; and (d) disconnect the QF without notice if, in Company's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or Company's facilities or other

customers' or third parties' property and facilities from damage or interference caused by Customer's QF, or improperly operating protective devices.

4.4 All suitable easements or rights-of-way (required by Company in order to accommodate inter-connection of Company's system with the QF), which are either on premises owned, leased or otherwise controlled by Customer, or upon other property, will be furnished in Company's name by Customer without cost to or condemnation by Company and in reasonable time to meet the requirements of the Purchase Agreement. All easements or rights-of-way obtained on behalf of Company will contain such terms and conditions as are acceptable to Company.

4.5 Company is not obligated to pay for electric energy or capacity from Customer during any periods when such purchases would result in costs greater than those which Company would otherwise incur had Company generated said energy itself or purchased the energy from another source. Company will give reasonable notice to Customer when such periods exist, so that Customer can discontinue deliveries of energy to Company or elect to continue to sell to Company at a rate, lower than the standard purchase rate, estimated to be the avoided system cost for the period during which such situations exist.

4.6 Company will not install and maintain any lines or equipment on Customer's side of the Point of Interconnection except its meter (and possibly some research equipment). For the mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the interconnection between Company's system and that of Customer's QF. Such employees carry credentials which they will show to Customer upon request.

4.7 The particular rate for purchases applicable to a QF may be dependent on the system configuration of its facilities. Because of the varied and diverse requirements and operating characteristics associated with such facilities, it will be the QF's responsibility to evaluate and determine which system configuration and attendant purchase rate is most appropriate. Company will cooperate with Customer by providing suitable information to enable the Customer to assess the options available; provided, however, that no such information or assistance will be deemed a representation or warranty by Company with respect to the contents of such information or any particular option available to Customer.

4.8 Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules or at Company's option.

4.9 The interconnection of Company's system with that of Customer will normally be arranged to accept only one type of standard service at one Point of Interconnection. However, if Customer's QF requires a special type of service (e.g., supplemental,

back-up, maintenance or interruptible power in addition to its normal service), or its sales to Company are at a different voltage level than that of its purchases from Company, such service(s) will be provided pursuant to the specific terms outlining such requirements in the Purchase Agreement, applicable rate schedules, and/or other supplemental or special terms and conditions governing such service.

4.10 Each premise owned or controlled by Customer which is served by Company under the Purchase Agreement will be metered and billed separately. As used herein, the term "premises" will be deemed to mean a single tract of land owned or controlled by Customer, or separate adjacent or contiguous tracts of land owned or controlled by Customer, operated by it as one tract under the same name or as part of the same business, and not separated by any private or public lands or rights-of-way owned or controlled by third parties.

4.11 All bills rendered for Company services provided to Customer under the provisions of the Purchase Agreement are due and payable upon presentation and are past due fifteen calendar days after mailing of bill. Company reserves the right to suspend or terminate Customer's service for non-payment of service bills past due, for non-payment of interconnection charges, and for non-payment of meter test charges. Past-due service bill amounts, past-due interconnection charges and past-due meter test charges, are subject to an additional charge at the rate of 1-1/2% per month during the period of delinquency.

5. Service offered under Special Agreement

Purchases will be made from Customer's QF in accordance with the Purchase Agreement, these terms and conditions and any changes required by law, regulation, rule, or order of applicable governmental authority, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of QF's, whose requirements are of unusual size or characteristics, additional or special rate and contract arrangements may be required.

6. Regulatory Authority

The rates, terms and other contract provisions governing electric power sold to Customer and the rates or other contract provisions for purchases by Company from Customer are subject to the jurisdiction of the Arizona Corporation Commission (ACC) and nothing contained herein will be construed as affecting or limiting in any way the right of Company (a) to make unilateral filings of changed rates, terms and other contract provisions, which will be effective when filed, or within a specified number of days thereafter as specified therein, such rates or other contract provisions specified in such filing to be subject to modification if required by a final decision of the ACC, or (b) to unilaterally make application to the ACC for changes in such rates or other contract provisions, following a hearing and decision as permitted by law and the ACC's rules and regulations.

7. Indemnity and Insurance

Each Party hereby agrees to indemnify the other Party, its officers, agents, and employees against all loss, damages, expenses and liability to third persons for injury to or death of person or injury to or loss of property, proximately caused by the indemnifying Party's construction, ownership, operation, or maintenance of, or by failure of, any of such Party's works or facilities used in connection with the Purchase Agreement. The indemnifying Party will, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party will also pay all costs and expenses that may be incurred by the other Party in enforcing this indemnity.

8. Uncontrollable Forces

No Party will be considered to be in default in the performance of any of its obligations under the Purchase Agreement (other than obligations of said Party to pay sums to be paid by it hereunder, and other costs and expenses) when a failure of performance will be due to an uncontrollable force. The term "uncontrollable force" will be any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, strikes, labor or material shortage, sabotage, restraint by court order or public authority, and action or non-action by or inability to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it will be unable to overcome. Nothing contained herein will be construed so as to require a Party to settle any strike or labor dispute in which it may be involved. Either Party rendered unable to fulfill any of its obligations under this Agreement by reason of an uncontrollable force will give prompt written notice of such fact to the other Party and will exercise due diligence to remove such inability with all reasonable dispatch.

9. Notices

Any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other may be so given by certified or registered mail, addressed to the Party or personally delivered to the Party at the place designated in the applicable section of the Purchase Agreement. Changes in such designation may be made by notice similarly given.

10. Conflicts

In case of an inconsistency or conflict between any provision of the Purchase Agreement, a rate schedule or these terms and conditions, the inconsistency will be resolved by giving priority to the Purchase Agreement, the rate and then the terms and conditions in said respective order.

11. Successors and Assigns

Purchase Agreement will be binding upon and for the benefit of the successors and assigns of Customer and Company, but no assignment by Customer will be binding until accepted in writing by Company (which acceptance will not be unreasonably withheld) and until the assignee in writing assumes the obligations of Customer under the Agreement.

General Description

This schedule establishes the terms and conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1. **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2. **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

1.3. **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.4. **Conversion** means converting overhead distribution facilities to underground facilities.

1.5. **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.

1.6. **Doubtful Permanency means** a customer who, in the opinion of the Company, is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.7. **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding

taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8. **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9. **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment, installed solely to serve an individual applicant or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10. **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11. **Irrigation** means water pumping service.

1.12. **Limited-Income Multi-Unit Residential Housing** means multi-unit housing that primarily leases to lower income or very low-income residents as defined by the U.S. Department of Housing and Urban Development HUD Public Housing Program.

1.13. **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicant's successors in interest with Company approval, which approval will not be unreasonably withheld.

1.14. **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.15. **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.16. **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.17. **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.18. **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things

as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.19. **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.20. **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.21. **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.

1.22. **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.23. **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.24. **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.25. **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed

1.26. **Arizona Rural Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.27. **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Arizona Rural Municipality, and where the Arizona Rural Municipality will be the lease-holder for future permanent applicants.

1.28. **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.29. **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.30. **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

1.31. **Voltage** for purposes of APS rates, secondary voltage is considered 600v and below. Primary is considered 601v up to 69kv. Transmission is 69kv and above. For clearances or engineering purposes refer to APS's Electric Service Requirements Manual.

2. General Provisions for Service

2.1. **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), Temporary Applicants (Section 13), and Doubtful Permanency Customers (Section 14).

2.2. **Schedule of Charges** - An applicant requesting an extension will be provided a sketch showing the Extension Facilities and a quote based on the Schedule of Charges or other applicable details. When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Subdivisions 100 lots or greater or that require feeder, backbone and/or major infrastructure to serve development.

(D) Extension Facilities for General Service applicants that require feeder, backbone and/or major infrastructure or specialized equipment to serve project.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments, Residential Lot Sale, Corporate Business and Industrial Park Developments, or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.

2.3. **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

(C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

(D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

2.4. **Refunds** – The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) The Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High-Rise Development will be five years from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family Developments will be five years and will start three months from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

2.5. **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6. **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1. Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on an allowance under the following conditions:

(A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site plan has been approved and recorded in the county having jurisdiction.

(C) The total cost of the Extension Facilities (primary, secondary, service), as determined by Company, is less than $10,000 per applicant.

3.2. All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3. Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5. The allowance cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

4. Residential Subdivision Developments

4.1. Extension Facilities will be installed to Residential Subdivision developments of four or more homes in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If the final approved plat is different from

what was originally submitted to the Company, it may cause delays and additional cost for redesign.

4.2. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition or organizational structure of developer.

4.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights.

4.6. The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date the Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7. Examples of the application of Section 4 can be found in Attachment 1 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1. Extension Facilities will be installed to residential "Lot Sale" developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate.

5.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

5.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the

costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan

5.5. Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1. Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2. The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate.

6.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

6.4. Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

7.1. Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost estimate.

7.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition, or organizational structure of applicant.

7.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights etc.

7.6. The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8. General Service Provisions

8.1. Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9. Basic General Service

9.1. Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2. The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3. The cost for Extension Facilities that require feeder, backbone, major infrastructure, or specialized equipment to serve the project, will be determined in accordance with a Project-Specific Cost Estimate.

9.4. Economic Feasibility Analysis for Basic General Service Applicants - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the

project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(E) Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(F) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10. High Rise Developments

10.1. Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS' Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

10.3. Economic Feasibility Analysis for High Rise Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4. Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

11. Mixed-Use Developments

11.1. Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

11.3. Economic Feasibility Analysis for Mixed Use Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant’s Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4. Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12. Corporate Business & Industrial Park Developments

12.1. Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2. The cost of installing Extension Facilities will be determined in accordance with a Project-Specific Cost Estimate.

12.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

12.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

12.5. Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13. Temporary Applicants

13.1. Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate.

13.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3. When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14. Doubtful Permanency Customers

14.1. When, in the opinion of Company, permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

14.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15. Municipalities and Other Governmental Agencies

15.1. Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2. The effective date for projects enacted under this provision for purposes of Section 2.4 will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16. Change in Applicant's Service Requirements

16.1. Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17. Relocations, Conversions and Upgrades of Company Facilities

17.1. **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2. **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3. **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

18. Additional Primary Feed or Specialized Equipment

18.1. When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19. Unusual Circumstances

19.1. In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20. Abnormal Loads

20.1. Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21. Master Metering

21.1. **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion is individually metered by Company.

21.2. **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable under the following conditions:

(A) For Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care or;

(B) For Limited-Income Multi-Unit Residential Housing that uses solar power in a "behind-the-meter" application

21.3. **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4. **Conversion from master meter to individually metered system** - Company will convert its facilities from a master metered system to a permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22. Voltage

22.1. All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2. Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.

23. Point of Delivery

23.1. For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

23.2. For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.

23.3. For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

24. Easements

24.1. Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension will be obtained by applicant and provided to Company in Company's name without cost to or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25. Grade Modifications

25.1. If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26. Measurement and Location

26.1. Measurement must be along the proposed route of construction.

26.2. Construction will be on public streets, roadways, highways, or easements acceptable to Company.

26.3. The Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27. Agreements

27.1. **Study and Design Agreements** - Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When

the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.

27.2. **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension; otherwise, the payment will be non-refundable.

27.3. **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28. Applicant Construction of Company Distribution Facilities

28.1. Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2. This option is not available for the following:

(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.

(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3. All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4. Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5. Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6. A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7. For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8. Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29. Settlement of Disputes

29.1. Any dispute between the applicant or prospective applicant and the Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30. Policy Exceptions

30.1. This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission.

(A) The following exceptions have been approved for Rural Municipality applicants:

i. Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by permanent applicants.

ii. The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

iii. The refund eligibility period for Rural Municipal Business Developments will be 7 years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

iv. Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the 7th year refundable period. Any unrefunded advance balance paid at the

start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement.

v. Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

vi. The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

vii. Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

(B) The following exceptions for sections 3, 7, 9, 10, and 11 have been approved for Hopi and Navajo applicants for the extension of electric service to residential and commercial buildings within the Navajo Nation and the Hopi Reservation that are in the APS service territory.

i. APS distribution facilities will be extended up to 2,000 feet at no cost to such applicants.

ii. Applicants requiring distribution facilities extending more than 2,000 feet will pay the amount as calculated through the schedule of charges or project specific costs for any distribution facilities after the initial 2,000 feet from existing APS distribution consistent with the application sections of this schedule.

SCHEDULE OF CHARGES

Description	Rate	Unit
Single Family Underground	$ 8.40	Per foot
Single Family Overhead	$ 22.40	Per foot
Residential Subdivision*	$ 12.26	Per foot
General Service and Commercial, Single Phase, Underground	$ 16.06	Per foot
General Service and Commercial, Single Phase, Overhead	$ 28.12	Per foot
General Service and Commercial, Three Phase, Underground	$ 42.81	Per foot
General Service and Commercial, Three Phase, Overhead	$ 59.04	Per foot
Single Phase Pole Interset (pole set in existing line)	$ 7,133.39	Each
Three Phase Pole Interset (pole set in existing line)	$ 9,378.39	Each
*Residential Subdivision projects with 100 or more lots will be determined via project specific costs.		

Attachment 1
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

SERVICE SCHEDULE 4
TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

General Description

As outlined in this schedule, Arizona Public Service Company (APS or Company) Customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SES) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering.

1. **Definitions**
   - 1.1 **Totalized Metering** is the measurement, for billing purposes, through one meter, and on the appropriate rate, of the simultaneous demands and energy of a Customer who receives electric service at a single site, through more than one SES.
     - (A) **Adjacent -** located in a continuous enclosure or in enclosures located within 10 feet of each other and operated as one integral unit under the same name and as part of the same business.
     - (B) **Remote -** located in enclosures separated by more than 10 feet that are contiguous sites not separated by private or public property or right-of-way and operated as one integral unit under the same name and as part of the same business.
   - 1.2 **Virtual Totalizing -** Where APS is not able to meter an Adjacent or Remote totalized installation from a single meter, typically due to metering technology not being available, APS may offer to virtually meter the Customer's site.

2. **Totalized Metering Qualifications** – in order to qualify for Totalized Metering, either Adjacent or Remote, the Customer must meet conditions 2.1 through 2.8:
   - 2.1 The Customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in APS's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 9.3); and
   - 2.2 Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and
   - 2.3 Three phase and single phase service entrance sections cannot be combined for totalizing purposes; and
   - 2.4 For Standard Offer Customers, totalized metering may be accomplished by providing electronically totalized demand and energy reads or by means of a physical wire interconnection of metering information with the Customer providing conduit between the SES; for Direct Access Customers the Customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with APS's Schedule 10, Terms and Conditions for Direct Access; and

2.5 The Customer will provide vault or transformer space, which meets APS specifications, on the Customer's property at no cost to APS; and

2.6 If the Customer operates an electric generation unit on the premises, totalized metering will be permitted when the Customer complies with all of APS's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected Customer owned generation; and

2.7 Written approval by APS's authorized representative is required before totalized metering may be implemented; and

2.8 Customers electing to have accounts either Adjacent or Remote Totalized metered will be required to maintain the accounts in the approved totalized configuration for a minimum of one year.

3. **Adjacent Totalized Metering Qualifications** - In addition to the Totalized Metering qualifications listed in Section 2, the following conditions (3.1 - 3.3) must also be met in order to qualify for Adjacent Totalized Metering:

3.1 The Customer's total load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

3.2 Load must be split and served from multiple SES; and

3.3 The Customer must locate SES to be totalized within 10 feet of each other.

4. **Remote Totalized Metering Qualifications** - In addition to the Totalized Metering qualifications listed in section 2, the following conditions (4.1 - 4.4) must also be met in order to qualify for Remote Totalized Metering:

4.1 Multiple SES are separated from one another by more than 10 feet; and

4.2 Each of the Customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

4.3 The Customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

4.4 The Customer has made a non-refundable contribution for the net additional cost to APS of the meter totalizing connection and equipment.

5. **Additional Charges**

5.1 There will be no additional charge to the Customer's monthly bill for Adjacent Totalized Metering.

5.2 When the total capital investment by APS to provide service at multiple points of delivery, as computed by APS, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge will be made to the Customer

receiving Remote Totalized Metering. However, lower capital investment which results from the Customer's contribution, other than the meter costs in 4.4 above, will not be considered.

5.3 For Customers where the total capital investment by APS to provide service at multiple points of delivery, as computed by APS, is greater than the cost to serve at a single point of delivery, then there will be an additional charge. The additional monthly charge for each delivery point above one will consist of 1% of the totalized bill, plus $500.00, plus applicable taxes and adjustments.

6. **Removal of Totalized Metering Configuration**

6.1 In some cases, it may be to the Customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

(A) The Customer must submit a written request to APS stating the reason for the removal and the specific equipment to be removed.

(B) After removal of the equipment, the Customer may not ask for services to be totalized for one year from the removal date. At the end of one year, if the Customer does request services to be totalized, the applicable conditions listed above must be met.

(C) The Customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

6.2 In the event the Customer should elect to remove a meter from a totalized metering configuration, the Customer will continue to be responsible for the minimum billing kW parameters noted on the Customer's Electric Supply Agreement.

6.3 Customer may elect an alternate rate schedule for accounts that are removed from the totalized configuration; however, no further rate schedule changes may be made within the succeeding 12-month period in accordance with provisions of APS's Schedule 1.

7. **Miscellaneous**

7.1 For public elementary and secondary schools (K-12) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SES), the sizing limitation outlined in 3.1, 3.2, 4.2, and 4.3 of this Schedule will not apply for the purpose of totalized metering qualification. School customers may elect General Service (E-32), Time-of-Use General Service, and GS-Schools Time-of-Use rate schedules for the totalized configuration.

General Conditions

Arizona Public Service Company (APS or Company) will have no liability of obligation for claims arising out of the procedures for curtailment or interruption of electric service implemented in accordance with these guidelines or any future supplemental, amendatory or implementary guidelines or regulations established by law.

Company will endeavor to identify Customer(s) who might be classified as having either Essential or Critical loads. In the event that a Customer is dissatisfied with APS's classification of their load, the Customer may bring the matter to APS or the Arizona Corporation Commission (ACC) and request a different classification. Until a redetermination is made by APS or the ACC, the Customer's original classification for purposes of electric curtailment under this Schedule will be unaffected.

As circumstances permit, and as further discussed in APS's Electric Load Curtailment Plan, Company will endeavor to notify County emergency personnel or similar local authorities of existing or developing situations involving the curtailment or interruption of APS Customers.

1. Definitions

1.1 **Essential Loads** – Loads necessary to serve facilities used to protect the health and safety of the public, such as hospitals, 911 Centers, national defense installations, sewage facilities and domestic water facilities. Loads necessary to serve 911 Centers, police stations, and fire stations, which do not have independent back-up generation and require APS's electric service for operation of essential emergency equipment.

1.2 **Critical Loads** – That portion of the electric load of nonresidential Customers, which in the event of 100 percent curtailment of service, would cause excessive damage to equipment or material being processed, or where the interruption would create grave hazards to employees or the public.

1.3 **Major Use Customers/Others (With Notice)** – Those Customers having relatively large loads (over 1000 kW) or a substantial number of employees or other special circumstances that make it appropriate to schedule blackouts or curtailments differently than typical Customers. Customers who qualify as Major Use/Others (With Notice) can take 100 percent curtailment when sufficient notice is provided. These loads will be interrupted after the required notification period. "Sufficient", "required", and "appropriate" notice is that notice that APS, after consultation with the affected Customer, has determined will allow the Customer to curtail in a safe and efficient manner. The notice necessarily will vary from Customer to Customer.

1.4 **Others (With or Without Notice)** – All Customers not meeting the above definitions. These Customers will be interrupted (with or without notice) if voluntary curtailment measures are not sufficient to alleviate the situation.

2. Applicable Guidelines - For interruption or curtailment of electric service due to power supply interruptions, fuel shortage, or transmission emergency. (Also see Arizona Administrative Code R14-2-208(E), Provision of Service.)

2.1 Regulatory reliability requirements that may cause APS to shed firm customer load may include the following:
(A) Capacity and Energy Emergency (EOP-002-3.1)
(B) Disturbance Control Performance (BAL-002-1)
(C) To relieve or prevent an SOL or IROL Exceedance (PEAK SOL Methodology Guideline, (TOP-008-1)
(D) To Prevent Voltage Collapse (VAR-001-3)

2.2 In the event firm Customer load shed becomes necessary it will be done using the following method:
(A) Circuits not classified with "Essential", "Critical", or "Major Use Customers/Others (with Notice)" Customers will be interrupted on a rotating basis. The frequency and duration of the interruptions will depend on the magnitude and nature of the power shortage. The frequency and duration of interruptions will also consider the circumstances of Major Use Customers.
(B) Accurate records will be kept to ensure that these circuits are rotated in an equitable and technically feasible manner.
(C) Circuits classified as "Major Use/Others (with Notice)" will be interrupted upon the giving of appropriate notice.
(D) Customers on circuits which serve critical loads will be required to curtail the non-critical portion of their loads. Thereafter, circuits that serve critical loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as critical may be curtailed if they possess back-up generation sufficient to meet their entire load requirement. If a Customer having a critical load refuses or fails to curtail their electric consumption down to the critical load, they will not be considered to have a critical load for purposes of this Schedule.
(E) Circuits which serve essential loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as essential may be curtailed if they possess back-up generation sufficient to meet their entire load requirement.

2.3 Sudden Shortages of Power - In the event that time does not allow for the implementation of the Electric Curtailment Guidelines, Company may resort to its emergency operations procedures, with or without notice.

2.4 Automatic Load Shedding - In the event that there is a major electrical disturbance threatening the interconnected Southwest system with blackout conditions, emergency devices such as under frequency load shedding, transfer tripping, etc., will be utilized to maintain the optimum system stability.

3. **Electric Curtailment of Firm Wholesale Customers**

3.1 The term "firm wholesale Customer" will be defined as those APS Customers who purchase, on a firm basis, electricity from APS for purposes of resale.

3.2 In any given instance where a curtailment of wholesale power deliveries is involved, and subject to any required approvals of the Federal Energy Regulatory Commission or contractual provisions to the contrary, Company shall notify its firm wholesale Customers, requesting that they curtail electric service to their retail Customers during the period that Company's system is affected by power shortages. In the event that Company is unable to obtain the cooperation of a firm wholesale Customer, it may seek an order from appropriate governmental authority requiring the firm wholesale Customer to accept a reduction of electricity deliveries proportionate to the curtailment being effected on Company's system.

4. Electric Load Curtailment Plan

4.1 A detailed Electric Load Curtailment Plan will be kept on file with the ACC. This plan will contain specific procedures for implementation of the above, along with the names and telephone numbers of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. The plan will be updated at least annually and become effective upon submission to the ACC.

4.2 APS will contact the Director, ACC Utilities Division, or their designee, as soon as practical for any curtailment or interruption of APS Customers under this Schedule 5.

General Description

This Service Schedule applies to any entity (Applicant) requesting to interconnect a generating facility, which is not otherwise subject to the Federal Energy Regulatory Commission (FERC) interconnection processes or rules, to Arizona Public Service Company's (APS or Company) power delivery system. *See* 18 C.F.R. § 292.306; *Western Massachusetts Electric Co.*, 61 FERC ¶61,182 at p. 61,661-62 (1992), *aff'd* 165 F.3d 922, 926 (D.C. Cir. 1999).

All services described in this Schedule are distinct from any similar-termed services provided by APS under FERC interconnection processes, which are not governed by this Schedule.

The construction or installation of interconnection facilities will be completed in accordance with the provisions of a separate agreement or contract.

1. Applicability

1.1 This schedule will only apply to:

(A) third-party-owned generation, a Qualifying Facility as defined in 18 C.F.R. § 292.203, for which the total generation output that is transmitted to the APS power delivery system is sold directly to APS; or

(B) APS-owned generation, generation that otherwise would meet the requirements in 18 C.F.R. § 292.203.

1.2 This Schedule will not apply to a generating facility that is interconnected at less than 1MW on the load side of an APS retail Customer's meter and is primarily intended to serve the Customer's electricity requirements, including, for example, a net metering facility as defined in A.A.C. R14-2-2302.

2. Study Services and Fees

2.1 Feasibility Studies - APS will conduct a preliminary review of the potential impacts of the proposed generating facility on the APS power delivery system. The study will assess the expected capacity requirements of the proposed generator on the delivery system compared with the available system capacity at the point of interconnection and identify any potential overload issues for the delivery system and circuit protection devices. Additionally, this study will provide an initial assessment of the complexity and likely costs for the interconnection.

(A) The Applicant will identify the proposed project site location before start of the study.

(B) Although the Feasibility Study is optional, no system impact or cost information will be provided by APS without the study and associated fee.
(C) The study fee for Interconnections below 69 kV is $5,000 per study (non-refundable).
(D) For Interconnections 69 kV and above, Applicant will pay APS's actual cost of performing the study.

2.2 System Impact Studies - APS will conduct a full technical review of the project's impact on the APS power delivery system, including power flow, stability analysis (69 kV and above only), APS system protective device coordination, system protection schemes and voltage drop. This study will determine if any upgrades to APS's system are required to build and interconnect the project as designed.
(A) The study fee for Interconnections below 69 kV is $15,000 per study. Fee will be reduced to $10,000 if a Feasibility Study has been completed by APS for the specific project (non-refundable).
(B) Applicant will pay APS's actual cost of performing study for Interconnections 69 kV and above.
(C) Although the System Impact Study is optional, no related information will be provided by APS without the study and fee.

2.3 Facilities Studies - APS will conduct a comprehensive analysis of the actual construction requirements for the APS power delivery system, based on the information from the Feasibility Study and System Impact Study or equivalent information provided by the Applicant or third party. The study will provide the detailed costs of construction and milestones associated with the requirements.
(A) This study is required for interconnection to the APS's power delivery system.
(B) Applicant will pay APS the actual cost of performing the Facility study.

3 Payment of Study Fees

3.1 For Interconnections below 69 kV, study fees will be due before the start of the study.

3.2 For Interconnections 69 kV and above, Applicant will pay APS a $20,000 deposit before the start of a Feasibility Study or a $40,000 deposit before the start of a System Impact Study. At the completion of a study the Applicant will pay APS any remaining fees above the deposit or APS will refund any excess deposit amount.

3.3 Before the start of a Facilities Study, Applicant will pay APS a $55,000 deposit. At the completion of the study the Applicant will pay any remaining fees above the deposit or will be refunded any excess deposit amount.

General Description

This Schedule establishes Arizona Public Service Company's (APS) meter maintenance and testing program for electric meters. APS will file an annual report with the Arizona Corporation Commission (ACC) summarizing the results of its meter maintenance and testing program.

1. Plan

1.1 Single-Phase and Three-Phase Self-Contained Meters - Solid State

APS will monitor performance of these types of meters through the Company's Metering and Billing systems.

1.2 Single-Phase Self-Contained Meters - Non-Solid State, Electro-Mechanical and Hybrid

(A) Based on ANSI C12.1 – 2008, meters will be grouped by common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four.

(B) Analysis of the test results for each group evaluated will be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 2008 Formulas B-3, Tables A-1, A-2 and B-5. When possible, the minimum sample size will be 100 meters.

1.3 Three-Phase Self-Contained Meters - Non-Solid State, Electro-Mechanical and Hybrid

APS will monitor installations of the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

(A) Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

(B) Three-phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.

(C) Three-phase lagged-demand meters: 8 years.

1.4 Transformer-Rated Meter Installations

APS will conduct inspections and accuracy testing for transformer-rated meter installations and the associated equipment according to the following schedule:

(A) Installations with less than 500 kW: APS will monitor performance of these types of meters through the Company's Metering and Billing systems.

(B) Installations with 500 to 1,000 kW loads: 4 years

(C) Installations with 1,001 kW to 2,000 kW loads: 2 years

(D) Installations over 2,000 kW loads: 1 year

Arizona Public Service Company (APS or Company) regularly encounters situations where a complete and valid meter read cannot be obtained. In such cases the customer's usage information must be estimated in order to render a bill. This schedule describes the circumstances, methods and procedures for estimating a customer's bill and is considered a part of all rate schedules.

1. GENERAL PROVISIONS

1.1 Causes that may result in an estimated bill include but are not limited to:

(A) Weather conditions that hinder meter access or compromise employee safety;

(B) Lack of access to the meter or the site;

(C) Malfunction of the meter, related equipment, or the Automated Meter Infrastructure (AMI) system;

(D) Labor limitations due to unforeseen illness, natural disasters, or other extreme events;

(E) Meter tampering or energy diversion;

(F) Inability to transfer meter data for billing.

1.2 The following are conditions under which a bill is not considered to be an estimate:

(A) Rate changes in the middle of the billing cycle when a valid read is available;

(B) Meter information obtained from a visual meter read rather than an electronic meter reading device;

(C) Direct access service using load profiles rather than meter data;

(D) A misread meter or estimated bill that is subsequently corrected with actual data. The rebill is considered a corrected bill.

2. ESTIMATION METHODS

APS will estimate the customer's billing information, such as monthly kWh consumption, monthly kW demand, on-peak kWh, and other information using the following methods:

2.1 The estimation procedure will start with the first method and proceed to a subsequent method if necessary – for example, if the required information is not available, is unreasonable, or was also estimated.

2.2 Under each method, available kWh data is used to determine a per-day usage value by dividing the total kWh by the number of days in the billing period. The per-day usage is then multiplied by the number of days in the current billing period to determine estimates for total and on-peak kWh usage. For rates with a kW demand component the demand will be the actual demand read from the available data.

2.3 In certain cases, the specific estimation methods and procedures in this schedule may not be appropriate or adequate. In such cases APS will use reasonable judgment in estimating the bill.

2.4 APS is not required to ask the customer to provide a meter read before estimating the bill.

Method 1 - AMI Data

With AMI data, a monthly meter read may be missing but information for part of the month may be available through daily meter reads. If sufficient AMI data is available, typically at least 11 days of usage data, the bill will be estimated using the available AMI data.

Method 2 – Previous Year Data

The bill will be estimated using available data for the same month last year, for the same customer at the same premises.

Method 3 – Previous Month Data

The bill will be estimated using available data for the previous month, for the same customer at the same premises.

Method 4 – Class Average Data

The bill will be estimated using average data for a designated class of customers.

3. DAILY BILL ESTIMATION

3.1 For bills that are based on daily meter information, missing data will be estimated using the most recent day for which adequate information is available for the premises. Missing weekday information will be estimated with the most recent available weekday information. Missing weekend and Holiday information will be estimated with the most recent available weekend day information. If historic daily meter information is not available

for the premises, the billing determinants will be estimated using class average data.

3.2 Additional conditions for Prepay Energy Services:

(A) Company will indicate on its web portal, within 24 hours, if the daily bill has been estimated.

(B) After no more than three consecutive days of estimation Company will take appropriate action to obtain the actual meter information and attempt to remedy any meter, communication, or other factors causing the need for estimation.

(C) If estimation is still necessary after three consecutive days, the Company will make reasonable efforts to avoid estimating energy usage for more than seven consecutive days. In the unlikely event a meter read cannot be obtained within seven consecutive days, the individual customer will be handled on a case by case basis and best efforts used to reach the mutual satisfaction of Customer and Company.

(D) Company will not disconnect the customer due to a negative account balance caused by an estimated read which has not been trued up with an actual read.

4. HOURLY DATA ESTIMATION

4.1 Where billing information is derived from interval data, such as 15 minute or hourly intervals, the estimates will be derived from a standard validating, editing and estimating (VEE) process as follows:

(A) Determine the kWh to be estimated: Compute the total kWh for the relevant time period by subtracting the start read from the stop read for that period, using the most recent reads. Sum the interval data for the same period to determine the kWh for the intervals having valid data. Compute the kWh for the interval data needing estimation (X): where (X) equals the total kWh for the period minus the kWh for the intervals with valid data.

(B) Determine the reference day(s): Select a reference day (or days) to provide an estimate of the load shape for the missing interval data. The reference day shall have a load shape that resembles the time period needing estimation. Weekday load shapes will be estimated with weekday reference days, weekends with weekend reference days. Holidays will be estimated with a weekend reference day.

(C) Replace the missing interval data with the reference day interval data for the same hour or sub-hour intervals of the day.

(D) Scale the reference day interval data: Sum the kWh for the reference day interval data that replaced the missing interval data (Y). Create a scale factor by dividing the kWh for the section needing estimation (X) by (Y). Multiply each estimated interval data point in the period by the (X/Y) scale factor.

5. SPECIAL CIRCUMSTANCES

5.1 Distributed Generation

The billing information for distributed generation, such as total generator output and excess power, will be estimated with the 4 methods described in this schedule, except that an engineering estimate may also be used if the other methods are not available.

5.2 Dead or Failing Meter

If the meter is dead or failing, APS will not adjust the bill until sufficient information is available from a new meter, typically 11 days or more of data. At that time any billing adjustments will be based on either the new billing information, adjusted for the days in the billing period, or Method 2 – Previous Year Data described in Section 2, whichever is lower. If APS believes that this estimate does not reasonably reflect the customer's actual usage, the estimate may be adjusted downward. Such billing adjustments are limited to three months for residential accounts and six months for non-residential accounts (See Schedule 1, Section 5).

5.3 Energy Diversion or Meter Tampering

If energy diversion or meter tampering has occurred the bill will be estimated using metered data from an auxiliary meter installed during the diversion investigation, meter information obtained after the diversion or tampering, consumption history before the diversion or tampering, or other reasonable sources of billing information as determined by Company.

5.4 Customer Supplied Meter Read

Some customers are approved to provide their own meter reads, consistent with ACC regulations. APS may estimate the bill if the customer fails to provide the read.

5.5 Meter Read Estimates Exceeding One Month

Estimates due to a malfunction of equipment that is owned or maintained by APS may exceed one month if the malfunction could not be reasonably discovered and corrected before the need for additional estimates. Estimates may also exceed one month if the equipment is owned or maintained by the customer.

6. TRUE-UPS OF PREVIOUS ESTIMATES

6.1 If a read from a previous month or day is estimated and a subsequent actual read is obtained, the following true-up will be performed.

6.2 Monthly kWh True-Up

If the current monthly kWh read is either lower than or substantially higher than the prior estimate, the kWh will be adjusted using the average kWh per day between the current read and the last valid read. The prior bill will be revised with the adjusted kWh applied to number of days in the billing period.

6.3 Daily kWh True-Up

If the current actual daily kWh read is either lower than or substantially higher than the prior estimate, the daily kWh will be adjusted using the average kWh per day between the current read and the last valid read. All prior affected daily bills will be revised with the adjusted kWh.

6.4 kW Demand True-Up

If kW demand was not reset and the current actual demand read is lower than the prior estimate, the previous billed demand will be adjusted downward to the new actual amount. The prior bill will be revised with the adjusted kW demand.

General Description

This Service Schedule provides the terms and conditions under which Arizona Public Service Company (APS or Company) may offer financial incentives to potential new commercial or industrial Customers or to existing commercial and industrial Customers who are adding significant new load.

Availability of this schedule is limited to the lesser of 125 MW of new and additional load or 50 new Customers with 25 MW reserved specifically for rural projects.

The Customer must provide all requested information to the Company in order to demonstrate eligibility. The Company will evaluate all relevant information and will determine whether to offer the Customer an incentive.

Consistent with the schedule, when the Company determines that it is appropriate to offer an incentive to an eligible Customer, an agreement will be executed with the Customer. The agreement will specify the incentive and other terms where different from the Company's other Service Schedules.

APS will submit each agreement, along with a complete Characteristics Report with Commission Staff for review. Each agreement submitted with the Commission Staff will become effective after 30 days.

Any Customer information that the Company provides to Commission Staff on a Confidential basis will be returned to the Company within 60 days.

1. Eligibility Criteria

The Company will evaluate the following Customer characteristics prior to offering service under this schedule to determine if the Customer is eligible for a financial incentive:

1.1 Availability of Alternative Locations

(A) Incentives are available only to Customers who have not located or expanded in the Company's service area before the Commission's review of the application and who would not locate or expand in the Company's service area without this schedule's incentive.

(B) The Customer must provide the Company with evidence that additional locations, outside the Company's service area, have been considered for location or expansion. This evidence must consist of written documentation including, but not limited to, detailed quantitative analyses performed by the Customer or consultants regarding the suitability of alternative locations.

(C) Based on the information provided, the Company will determine whether the Customer would reasonably locate elsewhere in the absence of the incentive. If so, the Customer will be deemed to have met this requirement.

1.2 Effects on Competitors

(A) Incentives will be available to the Customer only when existing Customers in the same line of business and market are not adversely impacted by the discounted rates.

(B) The Customer must provide a detailed description of goods and services produced, the technology employed, and the market(s) the Customer serves.

(C) Based on the provided information, along with knowledge of its customer base, the Company must reasonably verify that this requirement is satisfied for the Customer to be eligible for an incentive.

1.3 Customer Load Requirements

(A) To qualify for this schedule, electric requirements for a new Customer must be at least 2 MW and existing Customers must add at least 1 MW of load (the "New or Expansion Project"). To determine Customer load, APS will consider both energy purchased from the Company and any energy generated by the Customer using cogeneration or small power production facilities.

1. Notwithstanding 1.3(A), new customers locating to an Arizona Rural Municipality must be at least 1 MW to qualify.
2. Arizona Rural Municipality means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

(B) The Customer's monthly average load factor must be 55% or greater. This load factor criterion may be waived if one of the following apply:

1. The Customer's daily off-peak energy usage in kWh is greater than 50% of total monthly energy usage in kWh (off-peak hours will be defined using the applicable general service rate schedule); or
2. The Customer's new or added load is interruptible and the Customer's peak load is at least 3 MW.

(C) Loads that do not operate in the summer months of June through September will be given special consideration when determining an applicable incentive.

(D) APS will assist the Customer to consider and employ state-of-the-art, cost-effective energy conservation and demand response measures at its facility. These measures may include efficiency motors, motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.

1.4 Economic Requirements

(A) The load must be economic, as calculated under the Company's current extension policy using standard rates.

(B) To be eligible for incentives under this schedule, a potential load must bring a significant number of jobs or ancillary business into Arizona. In conjunction with this criterion, capital investment by the Customer may also be considered.

(C) The Company will give particular consideration to Customers whose electric bills exceed 5% of their operating expenses.

2. Conflict of Interest

2.1 In order to limit any potential conflict of interest, APS is required to submit an affidavit to Commission Staff for each Customer under consideration for service under this Service Schedule. This affidavit will include:

(A) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries, or one who has filled such role within the three-years prior to the effective date of the Customer's agreement, to the Company's knowledge, has or had any material interest, direct or indirect, in any substantial services, including real estate broker services, provided to the Customer in connection with the New or Expansion Project; and

(B) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has, or within the prior 12 months had, any direct or indirect material interest in any real property owned in whole or in part by the Customer in connection with the New or Expansion Project.

2.2 If the affidavit provided by APS is shown to be inaccurate, the Commission will, in future APS rate cases, impute as revenue the difference between the discounted rate and the tariffed rate which would otherwise apply to the Customer for the period during which the discount was in effect.

2.3 To the extent APS cannot obtain the requested affidavit, APS may submit an affidavit to Commission Staff disclosing the nature of any such known material interests and explain why an affidavit cannot be obtained.

3. Rate Provisions

3.1 A Customer satisfying the requirements above may receive an incentive to locate in the Company's service territory. The incentive will be a discount from the Customer's otherwise applicable base electric bill (excluding taxes and adjustments).

3.2 The discounted charges will not be below the Company's marginal cost.

3.3 The discount may vary over the term of the Customer agreement.

3.4 The discount will not be larger than 25% of the Customer's total energy bill from the Company.

3.5 No discount will be provided from the minimum bill as computed under the Customer's otherwise applicable rate.

3.6 For current customers adding load, the discount will apply only to the added load.

3.7 Any incentive available under this schedule will be limited to a specific period of six years or less.

3.8 The specific discount and the period over which the discount is applied will be determined after full evaluation of the Customer information as determined by the Company.

4. Characteristics Report

Each agreement must be accompanied by a Customer provided Characteristics Report. The following information will be included in the Characteristics Report provided by the Customer unless otherwise noted:

4.1 General Information
- (A) Customer name
- (B) Customer contact—name and address
- (C) Dates of Customer application and Company decision
- (D) New or existing Customer
- (E) Proposed effective date of agreement
- (F) The number of direct permanent full-time jobs being created in APS service territory
- (G) The average percent of County Median Wage for the direct jobs being created
- (H) The anticipated capital investment to be made by the Customer

4.2 Location Decision
- (A) Customer location
- (B) Description of other locations considered
- (C) Other locations of Customer's operations

(D) An affidavit from Customer demonstrating that the Customer would not locate or expand in Arizona absent the discounts
(E) Within ninety (90) days of the effective date of any agreement under this Schedule, the Customer must supply written documentation and analyses substantiating the affidavit provided under 4.2 (D)
(F) If the requirements of 4.2 (E) are not met within ninety (90) days of approval of the agreement, the agreement will be void
(G) Proportion of Customer's production and distribution expenses accounted for by electricity, by natural gas, and by other energy sources (specify)

4.3 Effects on Competitors
(A) Description of the business
(B) Number of other Customers in same business
(C) Market area served by Customer
(D) Description of effects on other Customers in Arizona

4.4 Load Characteristics
(A) Size of load
(B) Annual load factor
(C) Off-peak operation
(D) Description of daily load shape
(E) Seasonality
(F) Interruptibility
(G) Permanency of load
(H) Estimated impact on system peak demand from the new load

4.5 Energy Service Mix
(A) Use of natural gas and other energy sources
(B) Description of energy efficiency measures—building design, processing, and other
(C) Feasibility of cogeneration

4.6 Rates – APS Provided
(A) Applicable rate schedule
(B) Years discount will be in effect
(C) Percentage discount by year
(D) Estimated annual revenues
(E) Estimated annual incremental electricity production costs
(F) Support that the agreement meets the terms described in Rate Provisions 3.2 and 3.4

4.7 Special Agreement Provisions – APS Provided
(A) List of special provisions
(B) Reasons for special provisions

General Description

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, et seq., referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers will obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services will remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Under the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services when permitted as specified herein.

1. General Terms

1.1 Definitions - The definitions of principal terms used in this Schedule will have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

1.1.1 Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

1.1.2 Service Account - Unless otherwise stated, all references to "Service Account" in this agreement will refer to an installed service, identified by a Universal Node Identifier (UNI).

1.1.3 Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1 Non-Discrimination

2.1.1 Company will discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission (FERC) or applicable affiliate transactions rules, Company will not:

2.1.1.1 Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2 Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2 Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1 Timeliness, Due Diligence and Security Requirements

3.1.1 ESPs will exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs will make all payments owed to Company in a timely manner.

3.1.2 ESPs will adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2 Arrangements with ESP Customers

ESPs will be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company will not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3 Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4 Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5 Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1 ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation will not be used to compute Company charges or for tariff applicability.

3.5.2 Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision will not restrict the use of separate parties for metering and billing services.

3.6 Interval Metering

3.6.1 "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand

in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company will determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7 Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company will have access to meter data necessary for regulatory purposes or rate-setting purposes under mutually agreed upon terms with the ESP for such data access.

3.8 Statistical Load Profiles

Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers will pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10 Liability In Connection With ESP Services

3.10.1 "Damages" will include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2 Company will not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory

requirements related to Direct Access service, or as otherwise set forth in Company's Schedule 1.

3.10.3 Company will not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4 Company will not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5 An ESP is not a Company agent for any purpose. Company will not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances will Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision will not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. **Customer Inquiries and Data Accessibility**

4.1 Customer Inquiries - For customers requesting information on Direct Access, Company will make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list will not be considered an endorsement or other form of recommendation by Company.

4.2 Access to Customer Usage Data -For Company customers on Standard Offer Service, Company will provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1 ESPs may request Customer usage data before submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data at rates approved by the ACC.

4.2.2 Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquiries Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services will be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services will be directed to the ESP.

4.4 Customer Inquiries Related to Emergency Situations and Outages

4.4.1 Company will be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2 Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

5. **ESP Service Establishment**

5.1 Before the ESP or its agents can offer Direct Access services in Company's distribution service territory they must meet the applicable provisions as listed:

5.1.1 All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2 All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3 Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5 All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1 The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2 The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3 The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4 The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when

providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6 For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing will not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7 Compliance testing will be required for a MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6. **Direct Access Service Request (DASR)**

6.1 A DASR is submitted under the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and will also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs will have a CC&N from the ACC; will have entered into an ESP Service Acquisition Agreement with Company, if required, and will have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein will be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4 A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company.

A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5 Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site.

6.6 DASRs will be handled on a first-come, first-served basis. Each request will be time and date stamped when received by Company.

6.7 Once the DASR is submitted, the following timeframes will apply:

6.7.1 Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company will provide the reasons for the rejection. If a DASR is held pending further information, it will be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2 When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1 When Company is acting as the MSP, Company will perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days before the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP will notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8 DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days before the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days before the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates will be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10 If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received will be processed in that period. All subsequent DASRs will be rejected.

6.11 Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, will be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP will be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12 Customers returning to Company Standard Offer service must contact their ESP. The ESP will be responsible for submitting the DASR on behalf of the customer.

6.13 ESPs requesting to return a Direct Access customer to Company Standard Offer service will submit a TS DASR and will be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14 Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access service. Direct Access customers returning to Company Standard Offer service may be subject to the RCDAC-1.

6.15 Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees under Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16 A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17 Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18 Company will not hold the ESP responsible for any customer unpaid billing charges before the customer's switch to Direct Access. Unpaid billing charges will not delay the processing of DASRs and will remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company will not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer will not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company will not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 Subject to availability, and under the terms in the ESP Service Acquisition Agreement, this Schedule 10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company will bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company will comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills will include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP will receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers under the terms and conditions of the applicable ACC approved tariff.

7.2.3.2 The ESP will submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and under the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1 Bills under this option will be rendered once a month. Nothing contained in this Schedule will limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2 Except as provided in Section 7.2.4.1, Company will require that all ESP and Company charges be based on the same billing period data.

7.2.4.3 ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued under this Section may also include a message that Company charges were previously billed.

7.2.4.3 ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5 Restrictions

Company UDC Consolidated Billing will be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3 ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP will be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations

7.3.2.1 Company will calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company will provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill will include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP will comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges will be handled according to ACC procedures.

7.3.3.4 The ESP will process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans will not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company will continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP will process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, will receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company will make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company will continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included under the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) will resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, will be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error will contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company will be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP will be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the

charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP will be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer will be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company will transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP will apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP will be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company will remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late

charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges under Schedule 1. If an ESP fails to pay these charges before the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing under Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP will pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges under Schedule 1. If an ESP fails to pay these charges before the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing under Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company will be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company will not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP will assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments will be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules will apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account will be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP will be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company will not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety

violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company will notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges before disconnecting electric service to the Customer. Company will further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge will be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company will reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company will notify the ESP of a Customer's reconnection.

7.9.3 Company will not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10 Involuntary Service Changes

7.10.1 A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1 The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5 The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2 Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company will initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company will provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company will notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer will have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section will not disconnect electric service provided to Customer other than as provided in Section 4.4.2.

7.10.3 Change in Service Election Absent Exigent Circumstances

7.10.3.1 In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2)

or involve an ESP's unauthorized energy use, Company will notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1 The nature of the alleged failure;

7.10.3.1.2 The actions necessary to remedy the failure;

7.10.3.1.3 The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2 The ESP will have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and will notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section will not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4 Termination of ESP Consolidated Billing

7.10.4.1 Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1 The Company will notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2 If the ESP fails to pay Company (or dispute payment under the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company will notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers will be switched to Dual Billing.

7.10.4.1.3 If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers will be switched to Dual Billing.

7.10.4.2 Upon termination of ESP Consolidated Billing under Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in

compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP under the ESP Service Acquisition Agreement.

7.10.5 Termination of Company UDC Consolidated Billing

7.10.5.1 Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6 Upon termination of ESP Direct Access services under Section 7.10, the provision of the affected service(s) will be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company will provide such services, until such time that Customer makes an election.

7.10.7 Company will not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11 ESP Security Deposits

7.11.1 Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2 The amount of the security deposit required will not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a

separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3 Security deposits required under Section 7.11 will be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company will issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4 Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit under Section 7.11

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MRSP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for all Direct Access Customers.

8.2.1.1 If the ESP subcontracts with the UDC for Meter Services they must subcontract for both Metering and Meter Reading Services. The ESP will remain responsible for all cost associated with Metering, Meter Installation, Meter Communications and other MSRP related cost. All such cost will be authorized by the ACC.

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party or the UDC. If the ESP sub-contracts any of the components of these services to a third party or UDC, the ESP will, for the purposes of this Schedule, remain responsible for the services including communication equipment, meter reading equipment and associated maintenance necessary to obtain reads from specialized meters that may be required by a Direct Access Customers.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party or UDC assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards will apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test ANSI 57.13 Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services will also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters will have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, under the Rules, meters must be compatible with Company's AMI meter reading system.

8.6.3 No meter or associated metering equipment will be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter will be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service will be processed according to the following table before its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph AMI Meters	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing will be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record will be kept as long as the meter is in service.

8.8 Meter Test Requests

Under A.A.C. R14-2-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party will be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party will reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP will take reasonable measures to detect meter error. The MSP will notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP will make any repairs or changes required to correct the error. ESPs and Company will use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent will install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter will remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment will be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days before the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent will inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers under ACC Rules and Regulations, the ESP will be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent will return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent will be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP will be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter will ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements.

Company will perform a preinstallation inspection on all new construction. Local city/county clearances may also be required before energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC will coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership will be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment will be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 If the ESP or customer owns the meter, the ESP must own the CTs, PTs, and associated equipment, except as provided in Section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from Company at depreciated original cost.

8.12.3 The following provisions apply to the ownership of CTs and PTs.

8.12.3.1 For distribution voltages up to 25kV, the ESP or Company will own the CTs and PTs. For transmission primary voltages (over 25kV), the CTs and PTs will be owned by Company. ESP owned CTs and PTs must meet Company specifications. No CTs and PTs or associated metering equipment will be set or allowed to remain in service if it is determined that the CTs and PTs or their associated equipment does not meet Company's approved specifications, as set forth in Company's Electric Service Requirements Manual in place at the time of installation.

8.12.4 All CT-rated meter installations will utilize safety test switches, and all self-contained commercial metering will utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation and associated cost. Company may optionally provide meter installation under the provisions of this Service Schedule.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents will:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they will meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP will coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company will notify the ESP immediately and the ESP will notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP will ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and will notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations will perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least 10 days before the next scheduled read date. MRSP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers will be read, validated, edited, and transferred under Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file will be posted immediately.

8.15.2 Both Company and the ESP will have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data will include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data will be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data will contain applicable reason codes under the 867 guidelines.

8.15.4 The MRSP will provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs will read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter will contain the full period from read date to the following read date. Interval data cycles will be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp will begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 will constitute the billing cycle. For meter exchanges back to Standard Offer, every interval will be included up to the last full interval before the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP will provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for All Meters

8.16.1.1 Meter clocks will be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time will be accurate.

8.16.1.3 All meter reading data will be validated under the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Under guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data will be available by 3:00 p.m. Local Arizona Time (MST) on the second, working day after the scheduled read has been completed. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP will be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Before performing MRSP services in Company's distribution service territory, or before making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP will prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer will remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server will be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in Section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it will promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents will have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party will be responsible for all related expenses.

8.18.2.3 Company will adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement under section 7.10.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision will not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

General Description

Arizona Public Service Company (APS or Company) will provide specialized metering upon Customer request, if the Customer agrees to the following conditions:

1. The Customer must contact their APS Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR meter with KYZ pulse or modem options (including associated interfaces).

2. If the Customer requests a meter with a modem option, the Customer will be required to install coil of communication cable within five feet of the meter panel location and in such a manner that will provide for ease of attachment to the meter panel by APS. The phone line must be installed before the installation of the meter and will be located in such a manner as to not impede access to the metering equipment, the interior or exterior of the metering compartment, or other utility access panels. The Customer must provide APS with a phone number and any other communication access information to the meter(s) before APS's installation of the meter(s).

3. If a Customer requests kWh pulses, APS will furnish and install a Customer pulse interface and enclosure. Connections made by the Customer to the Customer pulse interface will not impede access to metering equipment, the interior or exterior of the metering compartment, or other utility access panels.

4. The Customer will be required to make a non-refundable contribution in aid of construction to APS for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

    4.1 If a meter currently exists on the Customer site, the charge is based on APS's total equipment and installation costs for the requested specialized metering less the equipment cost of APS's existing meter.

    4.2 If a meter has not been installed on the Customer site, the charge is based on APS's total equipment and installation costs for the requested specialized metering less 100% of the Adjusted Unit Cost (AUC) cost of an APS standard meter.

    4.3 If a specialized meter is existing on a Customer's site and the Customer requests an upgrade to a different type of meter, the Customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

5. APS will not place an order for a requested meter until payment has been received from the Customer. The typical lead time for procurement of meters is six to eight weeks. Once the requested meter(s) have been received, APS will schedule the installation of the meter(s) with the Customer or a designated representative.

6. APS will retain ownership of all meters and APS installed metering equipment.

7. If a Customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests APS to remove or replace the specialized meter, the Customer will not be eligible for a refund.

8. APS will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete, or inoperable, the Customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

9. APS will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

10. Under no circumstances will the Customer stop the operation or in any way affect or interfere with the operation of the Customer pulse interface and the related output wiring. The integrity of APS's billing metering equipment within the sealed metering compartment will be maintained.

11. APS reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the Customer's demand control or other equipment. However, APS will make a good faith effort to notify the Customer before any interruption of the specialized metering circuit.

12. The possible failure or malfunction of a KYZ pulse output or interface and subsequent loss of kWh contact closures to the Customer's control equipment will in no way be deemed to invalidate or in any way impair the accuracy and readings of APS's meters in establishing the kWh and demand record for billing purposes.

13. The accuracy of the Customer's equipment is entirely the responsibility of the Customer. Should the Customer's equipment malfunction, APS will reasonably cooperate with the Customer to the extent of ensuring that no malfunction exists in APS's equipment. Work of this nature will be billed to the Customer unless the actual source of the malfunction is found within APS's equipment.

14. If APS provides pulse values in kWh, Customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for APS to adjust the pulse values due to changes in APS's equipment.

15. No circuit for use by the Customer will be installed from APS's billing metering potential or current transformer secondaries.

16. APS reserves the right, without assuming any liability or responsibility, to disconnect and remove the pulse delivery equipment at any time upon 30 days written notice to the Customer.

17. Upon request by APS, the Customer will make available to APS monthly load analysis information.

18. References to electric kWh pulses above will mean dry KYZ contact closures only; the Customer is required to furnish operating voltage service. KYZ contacts are rated for and will not be wetted beyond a maximum of 100 milliampere and 120 volts DC or AC rms.

19. The Customer assumes all responsibility for and agrees to indemnify and save APS harmless against all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by APS resulting from the furnishing of specialized metering.

20. A waiver at any time by either party, or any default of, or breach by the other party or any matter arising in connection with this service, will not be considered a waiver of any subsequent default or matter.

21. Written approval by an authorized APS representative is required before electric kWh pulses service may be implemented.

A. RESIDENTIAL SERVICE

1. Residence - Single

Residential service to a single residence covers electric service to a private residence or individually metered apartment unit, only.

Outbuildings on the same premises may be connected to the residential service meter, but only if such outbuildings form a part of the general living establishment.

2. Residence - Multiple

Residential service to two or more residences on the same premises or a residence or residences subdivided into two or more individual housekeeping apartments shall not be supplied through one meter on a Residential Service Rate Schedule.

Individual meters will be installed by the Company for each individual dwelling or housekeeping unit. If, for any reason, a separate meter is not installed for each individual dwelling or housekeeping unit, then the appropriate General Service Rate Schedule will be used for billing for the service supplied through the single meter.

3. Professional Offices or Commercial Activities in Dwellings

The supply of service under a Residential Rate Schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the energy used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters.

Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electric equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises shall be classified as non-residential and the appropriate General Service Rate Schedule shall be applied. Customer may at their option provide separate circuits so that the residential uses can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

4. Farm and Rural Residences

The Residential Service Rate Schedules are available for electric service through one meter to a farm residence, and the usual farm uses outside the dwelling unit,

but not if the use extends to operations such as canning plants, packing plants, stone quarries, ice cream manufacturing plants, stores, restaurants, tea rooms, tourist and trailer camps, gasoline stations, automobile service stations, repair shops, blacksmith shops or any other commercial or non-farming operation. In no case shall the use extend to the processing, preparing or distributing of products not raised on the same farm and in no cases shall the use extend to a hatchery, dairy, butchery, greenhouse, or any other specialized operation unless such operation is conducted solely by the farmer and is incidental to the usual farm residence uses.

Customer may at his option elect to take the entire service under the appropriate General Service Rate Schedule, or may provide separate circuits so that the residential uses, together with the usual farm uses outside the dwelling unit, can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

The Residential Service Rate Schedules are not available for any use outside the dwelling unit on a farm which is not operated by an individual owner or lessee, occupying the farm residence.

B. GENERAL SERVICE

This covers service to any establishment for any purpose not prohibited by the rate schedule or Agreement for Service.

The General Service Rate Schedules are available only when all electric service required on the premises is taken through one meter at one point of delivery, except that:

(a) General Service Rate Schedules are available for more than one point of delivery on any one premise, provided that in such event, service supplied at each point of delivery will be separately metered and separately billed.

(b) The General Service Rate Schedules will be available for service to that portion of the Customer's premises which cannot be served at the Residential Service Rate Schedule or a Classified Service Rate Schedule. Service to such portion of the premises shall be considered as service to a separate Customer, and all electric service taken therein at the General

Service Rate Schedule must be through one meter at one point of delivery.

C. CLASSIFIED SERVICE

Classified service covers service for which specific rate schedules are available, due to the nature and load characteristics of the particular business. For such service, the General Service Rate Schedule may be used, except as specifically prohibited in that Schedule, while Classified Rate Schedules are available only to those businesses complying with the specific requirements of the particular schedule.

Service supplied under a Classified Rate Schedule shall be used only for the purposes specified in such rate schedule. In the event the Company questions whether the service is being used in compliance with said rate schedule, the Customer shall have the burden of establishing such compliance to the satisfaction of the Company. In the absence of such compliance, the Company may substitute an appropriate General Service Rate Schedule.

A Customer conducting mixed operations, a part of which may be served at a Classified Rate Schedule may, at his option, elect to take the entire service under the General Service Rate Schedule or may provide separate circuits so that the classified service can be metered and billed separately at the available classified schedule, and the other uses metered and billed under the available General Service Rate Schedule.

RATE SCHEDULE LEGACY E-12
RESIDENTIAL SERVICE FOR
LEGACY ON-SITE DISTRIBUTED GENERATION

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program.

This rate schedule is frozen effective September 1, 2017. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. In the winter season, all energy used is charged at a single price. In the summer season, energy is priced in blocks by usage, with charges that increase as usage increases. This rate does not have time-of-use charges or a demand charge.

TIME PERIODS

Summer Season: May through October billing cycles
Winter Season: November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.395 ~~0.320~~	per day

FROZEN

Energy Charges					
Summer			Winter		
First 400 kWh	$ 0.13213 ~~0.10828~~	per kWh	All kWh	$ 0.12841 ~~0.10528~~	per kWh
Next 400 kWh	$ 0.18914 ~~0.15429~~	per kWh			
Next 2200 kWh	$ 0.22158 ~~0.18046~~	per kWh			
Over 3000 kWh	$ 0.23639 ~~0.19241~~	per kWh			

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.088 ~~0.071~~	per day
Metering Charge	$ 0.125 ~~0.101~~	per day
Meter Reading Charge	$ 0.087 ~~0.070~~	per day
Billing Charge	$ 0.095 ~~0.078~~	per day

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00267~~	per kWh
Transmission Charge	$ 0.01097 ~~0.01097~~	per kWh
Delivery Charge	$ 0.03729 ~~0.03009~~	per kWh

Generation Charges					
Summer			Winter		
First 400 kWh	$ 0.08000 ~~0.06455~~	per kWh	All kWh	$ 0.07628 ~~0.06155~~	per kWh
Next 400 kWh	$ 0.13701 ~~0.11056~~	per kWh			
Next 2200 kWh	$ 0.16945 ~~0.13673~~	per kWh			
Over 3000 kWh	$ 0.18426 ~~0.14868~~	per kWh			

PROPOSED

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial requirements – Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount – Legacy
Legacy E-4	Limited income medical discount – Legacy
GPS-1, GPS-2, GPS-3	Green Power

FROZEN

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar Customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule, may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the Customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule, but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

FROZEN

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Electric service for some Customers is measured through two meters as part of a legacy water heating or space heating program. For these Customers, readings from the two meters will be combined for measuring total energy use.

FROZEN!

RATE SCHEDULE LEGACY ECT-1R
RESIDENTIAL TIME-OF-USE SERVICE
WITH DEMAND CHARGE FOR
LEGACY ON-SITE DISTRIBUTED GENERATION

FROZEN

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program that were on Rate Schedule ECT-1R prior to January 1, 2010.

This rate schedule was frozen beginning on January 1, 2010. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for this rate schedule is 9 a.m. to 9 p.m. Monday through Friday. All other hours are Off-Peak hours. The rate also varies by summer and winter season. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.770 ~~0.622~~	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 18.839 ~~15.170~~	$ 13.070 ~~10.524~~	per kW
On-Peak Energy Charge:	$ 0.10029 ~~0.08245~~	$ 0.07603 ~~0.06292~~	per kWh
Off-Peak Energy Charge:	$ 0.05515 ~~0.04610~~	$ 0.05351 ~~0.04478~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.330 ~~0.266~~	per day
Metering Charge	$ 0.258 ~~0.208~~	per day
Meter Reading Charge	$ 0.087 ~~0.070~~	per day
Billing Charge	$ 0.095 ~~0.078~~	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$ 5.422 ~~4.366~~	$ 3.198 ~~2.575~~	per kW
Generation On-Peak kW Charge	$ 13.417 ~~10.804~~	$ 9.872 ~~7.949~~	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387 ~~0.00267~~	per kWh
Transmission Charge:	$ 0.01097 ~~0.01097~~	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.02143 ~~0.01726~~	$ 0.02364 ~~0.01904~~	per kWh
Generation On-Peak kWh Charge:	$ 0.06402 ~~0.05155~~	$ 0.03755 ~~0.03024~~	per kWh
Generation Off-Peak kWh Charge:	$ 0.01888 ~~0.01520~~	$ 0.01503 ~~0.01210~~	per kWh

FROZEN

The kW used to determine the demand charge above will be the highest amount of demand averaged in a one-hour On-Peak period for the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. ~~The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~
5. ~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
6. ~~The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~
7. ~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
8. ~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements - Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount - Legacy
Legacy E-4	Limited income medical discount - Legacy
GPS-1, GPS-2, GPS-3	Green Power

FROZEN

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar Customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the Customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new Customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

PROPOSED

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

FROZEN

RATE SCHEDULE LEGACY ECT-2
RESIDENTIAL TIME-OF-USE SERVICE WITH DEMAND CHARGE FOR LEGACY ON-SITE DISTRIBUTED GENERATION

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program.

This rate schedule was frozen on September 1, 2017. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

FROZEN

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for this rate schedule is 12 p.m. to 7 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.770 ~~0.622~~	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 18.743 ~~15.096~~	$ 12.911 ~~10.399~~	per kW
On-Peak Energy Charge:	$ 0.12147 ~~0.09952~~	$ 0.07815 ~~0.06463~~	per kWh
Off-Peak Energy Charge:	$ 0.05969 ~~0.04976~~	$ 0.05538 ~~0.04629~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.330 ~~0.266~~	per day
Metering Charge	$ 0.258 ~~0.208~~	per day
Meter Reading Charge	$ 0.087 ~~0.070~~	per day
Billing Charge	$ 0.095 ~~0.078~~	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$ 6.248 ~~5.032~~	$ 3.332 ~~2.684~~	per kW
Generation On-Peak kW Charge	$ 12.495 ~~10.064~~	$ 9.579 ~~7.715~~	per kW

PROPOSED

Energy Charge Components

System Benefits Charge:	$ 0.00387 ~~0.00267~~	per kWh
Transmission Charge:	$ 0.01097 ~~0.01097~~	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.01943 ~~0.01565~~	$ 0.02208 ~~0.01778~~	per kWh
Generation On-Peak kWh Charge:	$ 0.08720 ~~0.07023~~	$ 0.04123 ~~0.03321~~	per kWh
Generation Off-Peak kWh Charge:	$ 0.02542 ~~0.02047~~	$ 0.01846 ~~0.01487~~	per kWh

The kW used to determine the demand charge above will be the highest amount of demand averaged in a one-hour On-Peak period for the month.

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. ~~The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~
5. ~~4.~~ The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
6. ~~The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~
7. ~~5.~~ The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
8. ~~6.~~ Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

FROZEN

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements - Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount - Legacy
Legacy E-4	Limited income medical discount - Legacy
GPS-1, GPS-2, GPS-3	Green Power

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

FROZEN

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

FROZEN

RATE SCHEDULE LEGACY ET-1
RESIDENTIAL TIME-OF-USE SERVICE FOR LEGACY ON-SITE DISTRIBUTED GENERATION

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program that were on Rate Schedule ET-1 prior to January 1, 2010.

This rate schedule was frozen beginning on January 1, 2010. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

FROZEN

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for this rate schedule is 9 a.m. to 9 p.m. Monday through Friday. All other hours are Off-Peak hours. The rate also varies by summer and winter season. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.772 ~~0.622~~	per day

	Summer	Winter	
On-Peak Energy Charge	$ 0.24749 ~~0.20048~~	$ 0.20050 ~~0.16274~~	per kWh
Off-Peak Energy Charge	$ 0.07894 ~~0.06512~~	$ 0.07533 ~~0.06222~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.331 ~~0.266~~	per day
Metering Charge	$ 0.259 ~~0.208~~	per day
Meter Reading Charge	$ 0.087 ~~0.070~~	per day
Billing Charge	$ 0.095 ~~0.078~~	per day

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00267~~	per kWh
Transmission Charge	$ 0.01097 ~~0.01097~~	per kWh
Delivery Charge	$ 0.03748 ~~0.03010~~	per kWh

	Summer	Winter	
Generation On-Peak Charge	$ 0.19517 ~~0.15674~~	$ 0.14818 ~~0.11900~~	per kWh
Generation Off-Peak Charge	$ 0.02662 ~~0.02138~~	$ 0.02301 ~~0.01848~~	per kWh

FROZEN

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements – Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount – Legacy
Legacy E-4	Limited income medical discount – Legacy
GPS-1, GPS-2, GPS-3	Green Power

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

PROPOSED

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new Customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

FROZEN

RATE SCHEDULE LEGACY ET-2
RESIDENTIAL TIME-OF-USE SERVICE FOR LEGACY ON-SITE DISTRIBUTED GENERATION
TIME ADVANTAGE 7PM-NOON

FROZEN

AVAILABILITY

This rate schedule is available to residential Customers that qualify for the residential solar grandfathering program.

This rate schedule was frozen on September 1, 2017. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate schedule for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate. Instead, the residential Customer will be served under an applicable retail rate of their choice.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for this rate schedule is 12 p.m. to 7 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.772 ~~0.622~~	per day

	Summer	Winter	
On-Peak Energy Charge:	$ 0.33776 ~~0.27307~~	$ 0.27392 ~~0.22178~~	per kWh
Off-Peak Energy Charge:	$ 0.08383 ~~0.06906~~	$ 0.08263 ~~0.06810~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.331 ~~0.266~~	per day
Metering Charge	$ 0.259 ~~0.208~~	per day
Meter Reading Charge	$ 0.087 ~~0.070~~	per day
Billing Charge	$ 0.095 ~~0.078~~	per day

Energy Charge Components

System Benefits Charge:	$ 0.00387 ~~0.00267~~	per kWh
Transmission Charge:	$ 0.01097 ~~0.01097~~	per kWh
Delivery Charge:	$ 0.03752 ~~0.03014~~	per kWh

	Summer	Winter	
Generation On-Peak Charge	$ 0.28540 ~~0.22929~~	$ 0.22156 ~~0.17800~~	per kWh
Generation Off-Peak Charge	$ 0.03147 ~~0.02528~~	$ 0.03027 ~~0.02432~~	per kWh

PROPOSED

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~
~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~
~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

Customers that interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014 will also be charged the Legacy Adjustment for Distributed Generation, Rate Rider Legacy LFCR DG.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial requirements – Net billing
EPR-6 Legacy Frozen	Partial requirements – Legacy Net Metering
Legacy E-3	Limited income discount – Legacy
Legacy E-4	Limited income medical discount – Legacy
GPS-1, GPS-2, GPS-3	Green Power

FROZEN

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and who otherwise qualify for this rate schedule may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted, and otherwise qualify for this rate schedule may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathered period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new Customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternative grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply, if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

FROZEN

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

FROZEN

RATE SCHEDULE R-1
RESIDENTIAL SERVICE
FIXED ENERGY CHARGE PLAN

AVAILABILITY

This rate schedule is available to full requirements residential Customers who do not have an on-site distributed generation system.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy or kilowatt-hours (kWh) is used during the month. This rate does not have time-of-use charges, seasonal charges, or a demand charge.

The Customer's applicable rate will be established by the annual average monthly energy consumption as determined by the Company. For Customers with an average monthly energy consumption of 600 kWh or less, the small tier (formerly Basic XS) charge applies. For Customers with an average monthly energy consumption of more than 600 kWh but less than 1,000 kWh, the medium tier (formerly Basic) charge applies. For Customers with an average monthly energy consumption of 1,000 kWh or more, the large tier (formerly Basic L) charge applies. For new residential Customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site.

Annual Review of Appropriate Usage Tier:
Annually in January, the Company will review the Customer's average monthly energy consumption during the previous 12 months. The Company uses Customer data from December of Year 1 through November of Year 2 to evaluate whether a Customer meets the usage criteria of the Customer's rate plan or should be reassigned. The Company will notify the Customer if the Customer's usage is below or exceeds the Customer's current energy usage tier, and that the Customer will be reassigned to a new tier consistent with the Customer's average monthly energy usage. The Company will provide each Customer whose average monthly usage during the year is approaching the next higher tier level at least two warnings about the consequences of exceeding the maximum threshold for the Customer's current tier.

The Company will provide a Customer a one-time waiver of this annual reassignment from the Customer's existing tier to the next higher tier based on the Customer's usage if the Customer contacts the Company.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Small - Tier 1 (Previously XS)

Basic Service Charge	$0.3930.316	per day
Energy Charge	$0.1384700.11298	per kWh

Medium - Tier 2 (Previously Basic)

Basic Service Charge	$0.5000.400	per day
Energy Charge	$0.1505300.12282	per kWh

Large - Tier 3 (Previously Basic L)

Basic Service Charge	$0.5000.400	per day
Energy Charge	$0.1653300.13478	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Small Tier

Basic Service Charge Components

Customer Accounts Charge	$0.0850.069	per day
Metering Charge	$0.1280.103	per day
Meter Reading Charge	$0.0850.068	per day
Billing Charge	$0.0950.076	per day

Energy Charge Components

System Benefits Charge:	$0.003870.00315	per kWh
Transmission Charge	$0.010970.01097	per kWh
Delivery Charge	$0.037340.02988	per kWh
Generation Charge	$0.086290.06898	per kWh

Medium Tier

Basic Service Charge Components

Customer Accounts Charge	$0.085~~0.068~~	per day
Metering Charge	$0.235~~0.188~~	per day
Meter Reading Charge	$0.085~~0.068~~	per day
Billing Charge	$0.095~~0.076~~	per day

Energy Charge Components

System Benefits Charge	$0.00387~~0.00315~~	per kWh
Transmission Charge	$0.01097~~0.01097~~	per kWh
Delivery Charge	$0.03734~~0.02988~~	per kWh
Generation Charge	$0.09835~~0.07882~~	per kWh

Large Tier

Basic Service Charge Components

Customer Accounts Charge	$0.085~~0.068~~	per day
Metering Charge	$0.235~~0.188~~	per day
Meter Reading Charge	$0.085~~0.068~~	per day
Billing Charge	$0.095~~0.076~~	per day

Energy Charge Components

System Benefits Charge	$0.00387~~0.00315~~	per kWh
Transmission Charge	$0.01097~~0.01097~~	per kWh
Delivery Charge	$0.03734~~0.02988~~	per kWh
Generation Charge	$0.11315~~0.09078~~	per kWh

ADJUSTMENTS

The Customer's bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~8.~~6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer's site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown below.

5. For purposes of A.R.S. §§ 33-1413.0l(B) and 33-2107(B)(3), the prevailing basic service single family residential rate charged by APS as the serving utility or provider is the middle tier of this tariff (Basic - 601-999 kWh).

RATE SCHEDULE R-2
RESIDENTIAL SERVICE
SAVER CHOICE PLUS

AVAILABILITY

This rate schedule is available to residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

This rate schedule was frozen as of December 1, 2021. This means a residential Customer that was already taking service under this rate schedule before that date may continue service under this rate schedule, but no customers connecting any service after that date will be eligible to choose to be served under this rate schedule.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will not vary by season.

TIME PERIODS

The On-Peak time period for this residential rate schedule is 3 p.m. to 8 p.m. Monday through Friday year-round. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

FROZEN

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.512 ~~0.409~~	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 10.116 ~~8.084~~	$ 10.116 ~~8.084~~	per kW
On-Peak Energy Charge:	$ 0.15623 ~~0.12709~~	$ 0.13042 ~~0.10648~~	per kWh
Off-Peak Energy Charge:	$ 0.09197 ~~0.07575~~	$ 0.09184 ~~0.07566~~	per kWh

FROZEN

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.088 ~~0.070~~	per day
Metering Charge	$ 0.240 ~~0.192~~	per day
Meter Reading Charge	$ 0.086 ~~0.069~~	per day
Billing Charge	$ 0.098 ~~0.078~~	per day

Demand Charge Components

Delivery On-Peak kW Charge	$ 4.844 ~~3.872~~	per kW
Generation On-Peak kW Charge	$ 5.272 ~~4.212~~	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge:	$ 0.01097 ~~0.01097~~	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.01339 ~~0.01070~~	$ 0.01326 ~~0.01061~~	per kWh
Generation On-Peak kWh Charge:	$ 0.12800 ~~0.10227~~	$ 0.10232 ~~0.08175~~	per kWh
Generation Off-Peak kWh Charge:	$ 0.06374 ~~0.05093~~	$ 0.06374 ~~0.05093~~	per kWh

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing month.

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to Partial Requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

FROZEN

9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-RES	Critical Peak Pricing (Residential)
E-3	Limited income discount
E-4	Limited income medical discount
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

3. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

4. Electric service is supplied at a single point of delivery and measured through a single meter.

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

FROZEN

6. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

FROZEN

RATE SCHEDULE R-EV
RESIDENTIAL SERVICE
ELECTRIC VEHICLE TIME-OF-USE ENERGY CHARGES

AVAILABILITY

This rate schedule is available to Standard Offer electric service required for residential purposes in individual private dwellings and in individually metered apartments.

This rate is available to residential customers subject to ready access to an AMI network, the installation of required metering equipment and implementation of meter changes, and the completion of necessary enhancements to the Company's billing system.

This rate schedule is only applicable to customers who own a qualified electric vehicle as determined by the Company. Service under this schedule is also subject to an annual certification for proof of EV ownership. Neighborhood Electric Vehicles as described in A.R.S. §28-101(53) do not qualify for this rate schedule.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak, Off-Peak or Super Off-Peak).

TIME PERIODS

The On-Peak time period for this residential rate schedule is 4 p.m. to 7 p.m. Monday through Friday. The Super Off-Peak time period is 11 p.m. to 5 a.m every day, including holidays. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge		$ 0.500 ~~0.400~~	per day
	Summer	Winter	
On-Peak Energy Charge	$ 0.49709 ~~0.40685~~	$ 0.46998 ~~0.38477~~	per kWh
Off-Peak Energy Charge	$ 0.13202 ~~0.10789~~	$ 0.13203 ~~0.10790~~	per kWh
Super Off-Peak Energy Charge	$ 0.03676 ~~0.03166~~	$ 0.03676 ~~0.03166~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.085 ~~0.068~~	per day
Metering Charge	$ 0.235 ~~0.188~~	per day
Meter Reading Charge	$ 0.085 ~~0.068~~	per day
Billing Charge	$ 0.095 ~~0.076~~	per day

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge	$ 0.01097 ~~0.01097~~	per kWh
Delivery On-Peak kWh Charge	$ 0.05080 ~~0.04137~~	per kWh
Delivery Off-Peak kWh Charge	$ 0.03734 ~~0.02988~~	per kWh
Delivery Super Off-Peak kWh Charge	$ 0.01326 ~~0.01061~~	per kWh

	Summer	Winter	
Generation On-Peak kWh Charge	$ 0.43145 ~~0.35136~~	$ 0.40434 ~~0.32928~~	per kWh
Generation Off-Peak kWh Charge	$ 0.07984 ~~0.06389~~	$ 0.07985 ~~0.06390~~	per kWh
Generation Super Off-Peak kWh Charge	$ 0.00866 ~~0.00693~~	$ 0.00866 ~~0.00693~~	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

RCP	Resource Comparison Proxy
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. This rate schedule requires the Customer to have a standard AMI meter in place.

2. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

3. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

4. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

5. Electric service is supplied at a single point of delivery and measured through a single meter.

6. This schedule is not applicable to breakdown, standby, supplemental or resale service.

7. Direct Access Customers are not eligible for this rate schedule.

AVAILABILITY

This rate schedule is available to residential Customers with the following:

1. Two or more qualifying primary on-site technologies purchased within 90 days of the Customer enrolling in the rate; or
2. One qualifying primary on-site technology purchased within 90 days of the Customer enrolling in the rate and two or more qualifying secondary on-site technologies.

This is a pilot rate schedule. This means this rate is associated with a specific program approved by the Arizona Corporation Commission, and is available only to those Customers eligible to participate in the program. The R-Tech pilot program will test the ability and desire of participating residential Customers to reduce On-Peak energy and demand usage through multiple behind-the-meter technologies.

Qualifying technologies for the R-Tech pilot program are as follows:

1. Primary technologies:
   a. A rooftop solar photovoltaic system. The size of the system cannot be smaller than 2 kW-dc. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the Customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the Customer's peak is 8 kW-ac, the maximum system size that could be installed would be 12 kW-dc).
   b. A chemical storage system. The size of the system cannot be smaller than 4 kWh. There is no maximum limitation for this technology.
   c. An electric vehicle. There are no limitations for this technology.

2. Secondary technologies:
   a. A device with a variable speed motor (such as a variable speed pool pump or a variable speed Heating, Ventilating, and Air Conditioning (HVAC) system).
   b. A grid-interactive water heating system.
   c. A smart thermostat.
   d. An automated load controller.

This rate schedule is initially limited to a maximum of 10,000 residential customers as outlined in Decision No. 76295.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the amount of demand (kW) averaged in a one-hour period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will also vary by season (summer or winter) and time of day (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for this residential rate schedule is 3 p.m. to 8 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Indigenous People's Day / Columbus Day – Second Monday in October
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge			$ 0.591 ~~0.473~~	per day
		Summer	Winter	
On-Peak Demand Charge		$ 24.284 ~~19.434~~	$ 17.089 ~~13.676~~	per kW
Off-Peak Demand Charge	First 5 kW	$0.000~~0.000~~	$0.000~~0.000~~	per kW
	All remaining kW	$ 7.797 ~~6.239~~	$ 7.797 ~~6.239~~	
On-Peak Energy Charge		$ 0.06733 ~~0.05613~~	$ 0.05533 ~~0.04653~~	per kWh
Off-Peak Energy Charge		$ 0.05533 ~~0.04653~~	$ 0.05533 ~~0.04653~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.154 ~~0.123~~	per day
Metering Charge	$ 0.257 ~~0.206~~	per day
Meter Reading Charge	$ 0.085 ~~0.068~~	per day
Billing Charge	$ 0.095 ~~0.076~~	per day

Demand Charge Components

		Summer	Winter	
On-Peak Generation Charge		$ 16.489 ~~13.196~~	$ 9.294 ~~7.438~~	per kW
Off-Peak Generation Charge	First 5 kW	$0.000~~0.000~~	$0.000~~0.000~~	per kW
	All remaining kW	$ 1.200 ~~0.960~~	$ 1.200 ~~0.960~~	per kW
On-Peak Delivery Charge		$ 7.795 ~~6.238~~	$ 7.795 ~~6.238~~	per kW
Off-Peak Delivery Charge	First 5 kW	$0.000~~0.000~~	$0.000~~0.000~~	per kW
	All remaining kW	$ 6.597 ~~5.279~~	$ 6.597 ~~5.279~~	

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge	$ 0.01097 ~~0.01097~~	per kWh
Delivery Charge for all kWh	$ 0.00252 ~~0.00202~~	per kWh

	Summer	Winter	
Generation On-Peak kWh Charge	$ 0.04997 ~~0.03999~~	$ 0.03797 ~~0.03039~~	per kWh
Generation Off-Peak kWh Charge	$ 0.03797 ~~0.03039~~	$ 0.03797 ~~0.03039~~	per kWh

The kW used to determine the On-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the month.

The kW used to determine the Off-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour Off-Peak period during the weekday (Monday through Friday), excluding holidays that may fall on a weekday.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

RCP	Resource Comparison Proxy
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. This pilot rate schedule requires the Customer to have a standard AMI meter in place.

2. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

3. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

4. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

5. Electric service is supplied at a single point of delivery and measured through a single meter.

6. Direct Access Customers are not eligible for this rate schedule.

RATE SCHEDULE R-3
RESIDENTIAL SERVICE
TIME-OF-USE 4PM TO 7PM WEEKDAYS
WITH DEMAND CHARGE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system. This schedule replaces Time-of-Use 3 p.m. to 8 p.m. Weekdays with Demand Charge in accordance with Arizona Corporation Commission-approved changes in Decision No. 78317. ~~Upon the completion of the required billing system updates and individual customer metering changes, customers will be served under this new rate schedule with on-peak hours of 4 p.m. to 7 p.m.~~

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak, Off-Peak, or Super Off-Peak). The demand charge also varies by season.

TIME PERIODS

The On-Peak time period for residential rate schedules is 4 p.m. to 7 p.m. Monday through Friday. This rate also has a Super Off-Peak period, which is 10 a.m. to 3 p.m. Monday through Friday during the winter season, which is the November through April billing cycles. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve – December 24**
- Christmas Day - December 25*
- New Year's Eve – December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge:	$ 0.500 ~~0.400~~	per day

	Summer	Winter	
On-Peak Demand Charge:	$ 21.113 ~~16.875~~	$ 14.820 ~~11.845~~	per kW
On-Peak Energy Charge:	$ 0.15250 ~~0.12414~~	$ 0.10615 ~~0.08711~~	per kWh
Off-Peak Energy Charge:	$ 0.06319 ~~0.05276~~	$ 0.06306 ~~0.05267~~	per kWh
Super Off-Peak Energy Charge:		$ 0.03676 ~~0.03166~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	$ 0.085 ~~0.068~~	per day
Metering Charge	$ 0.235 ~~0.188~~	per day
Meter Reading Charge	$ 0.085 ~~0.068~~	per day
Billing Charge	$ 0.095 ~~0.076~~	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$ 4.844 ~~3.872~~	$ 4.844 ~~3.872~~	per kW
Generation On-Peak kW Charge	$ 16.269 ~~13.003~~	$ 9.976 ~~7.973~~	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge:	$ 0.01097 ~~0.01097~~	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$ 0.01339 ~~0.01070~~	$ 0.01326 ~~0.01061~~	per kWh
Generation On-Peak kWh Charge:	$ 0.12427 ~~0.09932~~	$ 0.07805 ~~0.06238~~	per kWh
Generation Off-Peak kWh Charge:	$ 0.03496 ~~0.02794~~	$ 0.03496 ~~0.02794~~	per kWh
Generation Super Off-Peak kWh Charge:		$ 0.00866 ~~0.00693~~	per kWh

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing cycle.

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month up to a maximum of three instances per billing year, with only one of the three instances allowed during the summer season. This limitation is not available to Partial Requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP- RES	Critical Peak Pricing (Residential)
EPR-2	Partial R~~r~~equirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

3. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

4. Electric service is supplied at a single point of delivery and measured through a single meter.

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

6. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE
TIME-OF-USE 4PM-7PM WEEKDAYS

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system. This schedule replaces Time-Of-Use 3 p.m. to 8 p.m. Weekdays in accordance with Arizona Corporation Commission-approved changes in Decision No. 78317. ~~Upon the completion of the required billing system updates and individual customer metering changes, customers will be served under this new rate schedule with on-peak hours of 4 p.m. to 7 p.m.~~

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak, Off-Peak, or Super Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for residential rate schedules is 4 p.m. to 7 p.m. Monday through Friday year-round. This rate also has a Super Off-Peak period, which is 10 a.m. to 3 p.m. Monday through Friday during the winter season, which is the billing cycles of November through April. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Juneteenth – June 19*
- Independence Day - July 4*
- Labor Day - First Monday in September
- Indigenous Peoples' Day / Columbus Day – Second Monday in October
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Eve - December 24**
- Christmas Day - December 25*
- New Year's Eve - December 31**

*If these holidays fall on a Saturday, the preceding Friday will be Off-Peak. If they fall on a Sunday, the following Monday will be Off-Peak.

**The day on which these holidays fall will be Off-Peak days.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles, and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.500 ~~0.400~~	per day

	Summer	Winter	
On-Peak Energy Charge	$ 0.36935 ~~0.29780~~	$ 0.34944 ~~0.28185~~	per kWh
Off-Peak Energy Charge	$ 0.13202 ~~0.10789~~	$ 0.13203 ~~0.10790~~	per kWh
Super Off-Peak Energy Charge		$ 0.03676 ~~0.03166~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.085 ~~0.068~~	per day
Metering Charge	$ 0.235 ~~0.188~~	per day
Meter Reading Charge	$ 0.085 ~~0.068~~	per day
Billing Charge	$ 0.095 ~~0.076~~	per day

Energy Charge Components

System Benefits Charge		$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge		$ 0.01097 ~~0.01097~~	per kWh
	Summer	Winter	
Delivery Charge On-Peak	$ 0.03734 ~~0.02988~~	$ 0.03734 ~~0.02988~~	per kWh
Delivery Charge Off-Peak	$ 0.03734 ~~0.02988~~	$ 0.03734 ~~0.02988~~	per kWh
Delivery Charge Super Off-Peak		$ 0.01326 ~~0.01061~~	per kWh

Generation On-Peak Charge	$ 0.31717 ~~0.25380~~	$ 0.29726 ~~0.23785~~	per kWh
Generation Off-Peak Charge	$ 0.07984 ~~0.06389~~	$ 0.07985 ~~0.06390~~	per kWh
Generation Super Off-Peak Charge		$ 0.00866 ~~0.00693~~	per kWh

CHARGE FOR ON-SITE DISTRIBUTED GENERATION CUSTOMERS

The monthly bill for Customers on this rate schedule that have an on-site distributed generation system will also include a Grid Access Charge. This charge will apply to the nameplate kW-dc power rating of the Customer's distributed generation facility:

Grid Access Charge	$ - ~~0.00~~	per kW-dc of generation

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

3. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

4. Electric service is supplied at a single point of delivery and measured through a single meter.

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers who have consistent monthly energy and demand requirements.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge that varies based on the season. This plan is for Customers who have billing quantities that can be calculated without the use of metering equipment and service that can be supplied from a single point of delivery; such as sprinkler systems and cable television amplifiers.

TIME PERIODS

Summer season:	May through October billing cycles
Winter season :	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 0.487 ~~0.391~~	per day

	Summer	Winter	
Energy Charge	$ 0.16493 ~~0.13406~~	$ 0.14874 ~~0.12106~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts	$ 0.451 ~~0.362~~	per day
Billing	$ 0.036 ~~0.029~~	per day

Energy Charge Components

System Benefits	$ 0.00387 ~~0.00315~~	per kWh
Transmission	$ 0.00794 ~~0.00794~~	per kWh
Delivery	$ 0.05728 ~~0.04600~~	per kWh

	Summer	Winter	
Generation Charge	$ 0.09584 ~~0.07697~~	$ 0.07965 ~~0.06397~~	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~7.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SPECIAL PROVISIONS

1. Electric services being served on the Company's Rate Schedule E-30 prior to April 1, 2005 will continue to be served under this rate schedule; however, services eligible for this rate schedule after that date must meet the demand and energy requirements set forth below.

2. This rate schedule is only available to Customers whose monthly demand (kW) and energy (kWh) requirements remain constant. Monthly demand and energy requirements cannot exceed 1.44 kW (12 amperes) or 1,095 kWh at 120 volts, or 2.9 kW (12 amperes) or 2,117 kWh at 240 volts. Determination of fixed monthly energy usage will be calculated based on the manufacturer's nameplate rating of the equipment and based on an average 730 hour month.

3. Prior written approval by an authorized Company representative is required before service is implemented under this rate schedule.

4. Prior written approval by an authorized Company representative is required for any change in loads. An unauthorized load change will automatically disqualify that Customer from service under this rate schedule.

5. The Company shall have the right to inspect the Customer's load facilities at any time to ensure compliance with all provisions of this rate schedule.

6. Service must be supplied at one site through one point of delivery as specified by the written approval.

7. This schedule is not applicable to breakdown, standby, supplemental, residential, or resale service.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedules E-34 or E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges (only one applies)		
For service through Self-Contained Meters	$ 3.657 ~~2.891~~	per day
For service through Instrument-Rated Meters	$ 4.687 ~~3.705~~	per day
For service at Primary Voltage	$ 8.195 ~~6.477~~	per day
For service at Transmission Voltage	$ 46.362 ~~36.639~~	per day

Demand Charges (only one set applies)			
Secondary	First 100 kW	$ 29.731 ~~24.097~~	per kW
	All additional kW	$ 20.446 ~~16.760~~	per kW
Primary	First 100 kW	$ 26.954 ~~21.903~~	per kW
	All additional kW	$ 19.020 ~~15.633~~	per kW
Transmission	First 100 kW	$ 20.469 ~~16.778~~	per kW
	All additional kW	$ 13.452 ~~11.233~~	per kW

	Summer	Winter	
Energy Charge	$ 0.06642 ~~0.05258~~	$ 0.04470 ~~0.03542~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 2.872 ~~2.270~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.739 ~~0.584~~	per day
Instrument-Rated Meters	$ 1.769 ~~1.398~~	per day
Primary	$ 5.277 ~~4.170~~	per day
Transmission	$ 43.444 ~~34.332~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870 ~~2.870~~	per kW
Generation		$ 6.533 ~~5.163~~	per kW
Delivery - Secondary	First 100 kW	$ 20.328 ~~16.064~~	per kW
	All additional kW	$ 11.043 ~~8.727~~	per kW
Delivery - Primary	First 100 kW	$ 17.551 ~~13.870~~	per kW
	All additional kW	$ 9.617 ~~7.600~~	per kW
Delivery - Transmission	First 100 kW	$ 11.066 ~~8.745~~	per kW
	All additional kW	$ 4.049 ~~3.200~~	per kW

Energy Charge Components

System Benefits		$ 0.00387 ~~0.00315~~	per kWh
Delivery		$0.00000~~0.00000~~	per kWh
	Summer	Winter	
Generation	$ 0.06255 ~~0.04943~~	$ 0.04083 ~~0.03227~~	per kWh

For billing purposes, the kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32 TOU L that together have a combined load of at least 5 MW are eligible for a discount of $ (0.00293) ~~(0.00234)~~ per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~7.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements Service
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of greater than 100 kW and less than or equal to 400 kW.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges (only one applies)		
For service through Self-Contained Meters	$ 1.389 ~~1.110~~	per day, or
For service through Instrument-Rated Meters	$ 2.418 ~~1.932~~	per day, or
For service at Primary Voltage	$ 5.925 ~~4.733~~	per day, or
For service at Transmission Voltage	$ 44.093 ~~34.851~~	per day

Demand Charges (only one set applies)			
Secondary	First 100 kW	$ 14.007 ~~11.713~~	per kW
	All additional kW	$ 7.762 ~~6.754~~	per kW
Primary	First 100 kW	$ 12.927 ~~10.855~~	per kW
	All additional kW	$ 6.874 ~~6.049~~	per kW
Transmission	First 100 kW	$ 10.313 ~~8.780~~	per kW
	All additional kW	$ 4.073 ~~3.825~~	per kW

Energy Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.12666 ~~0.10065~~	$ 0.10727 ~~0.08532~~	per kWh
All additional kWh	$ 0.07811 ~~0.06210~~	$ 0.05891 ~~0.04678~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Metering* (only one applies)		
Self-~~-~~Contained Meters	$ 0.740 ~~0.591~~	per day, or
Instrument-Rated Meters	$ 1.769 ~~1.413~~	per day, or
Primary	$ 5.276 ~~4.214~~	per day, or
Transmission	$ 43.444 ~~34.332~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870	per kW
Delivery - Secondary	First 100 kW	$ 11.137 ~~8.843~~	per kW
	All additional kW	$ 4.892 ~~3.884~~	per kW
Delivery - Primary	First 100 kW	$ 10.057 ~~7.985~~	per kW
	All additional kW	$ 4.004 ~~3.179~~	per kW
Delivery - Transmission	First 100 kW	$ 7.443 ~~5.910~~	per kW
	All additional kW	$ 1.203 ~~0.955~~	per kW

Energy Charge Components

System Benefit Charge	$ 0.00387 ~~0.00315~~	per kWh
Delivery Charge	$ 0.01549 ~~0.01230~~	per kWh

Generation Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.10730 ~~0.08520~~	$ 0.08791 ~~0.06987~~	per kWh, plus
All additional kWh	$ 0.05875 ~~0.04665~~	$ 0.03955 ~~0.03133~~	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 15-minute period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown ~~below~~above.

AVAILABILITY

This rate schedule is available to non-residential Customers with a monthly load of 21 kW up to and including 100 kW.

DESCRIPTION

This rate has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter). Demand charges also vary by voltage.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges		
For service through Self-Contained Meters	$ 1.389 ~~1.110~~	per day
For service through Instrument-Rated Meters	$ 2.418 ~~1.932~~	per day
For service at Primary Voltage	$ 5.925 ~~4.733~~	per day

Demand Charges			
Secondary	First 100 kW	$ 13.177 ~~11.060~~	per kW
	All additional kW	$ 7.408 ~~6.476~~	per kW
Primary	First 100 kW	$ 12.286 ~~10.352~~	per kW
	All additional kW	$ 6.517 ~~5.768~~	per kW

Energy Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.12963 ~~0.10307~~	$ 0.11045 ~~0.08783~~	per kWh
All additional kWh	$ 0.08121 ~~0.06460~~	$ 0.06204 ~~0.04937~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Metering* (only one applies)		
Self-~~-~~Contained Meters	$ 0.740 ~~0.591~~	per day, or
Instrument-Rated Meters	$ 1.769 ~~1.413~~	per day, or
Primary	$ 5.276 ~~4.214~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission Charge		$ 2.870 ~~2.870~~	per kW
Delivery - Secondary	First 100 kW	$ 10.307 ~~8.190~~	per kW
	All additional kW	$ 4.538 ~~3.606~~	per kW
Delivery - Primary	First 100 kW	$ 9.416 ~~7.482~~	per kW
	All additional kW	$ 3.647 ~~2.898~~	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh
Delivery Charge	$ 0.01683 ~~0.01337~~	per kWh

Generation Charges			
	Summer	Winter	
First 200 kWh per kW	$ 0.10893 ~~0.08655~~	$ 0.08975 ~~0.07131~~	per kWh
All additional kWh	$ 0.06051 ~~0.04808~~	$ 0.04134 ~~0.03285~~	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 15-minute period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56 R	Partial Requirements – Renewable
GPS-1, GPS-2. GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers, and to Customers with secondary services at residential sites that are separately metered such as wells or detached garages.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter). This rate is a General Service rate for Customers with an average summer monthly maximum demand of 20 kW or less per month based on the Customer's average demand (kW) supplied during the 1-hour period of maximum use during the month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges		
For service through Self-Contained Meters	$ 1.389 ~~1.110~~	per day
For service through Instrument-Rated Meters	$ 2.418 ~~1.932~~	per day
For service at Primary Voltage	$ 5.925 ~~4.733~~	per day

Energy Charges:			
	Summer	Winter	
Secondary Service – First 5,000 kWh	$ 0.16199 ~~0.13104~~	$ 0.14227 ~~0.11527~~	per kWh
Secondary Service – All Additional kWh	$ 0.08930 ~~0.07298~~	$ 0.06916 ~~0.05689~~	per kWh
Primary Service – First 5,000 kWh	$ 0.15777 ~~0.12767~~	$ 0.13799 ~~0.11185~~	per kWh
Primary Service – All Additional kWh	$ 0.08468 ~~0.06929~~	$ 0.06493 ~~0.05351~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts Charges:	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Meter* (only one applies)		
~~——~~Self-~~-~~Contained Meters	$ 0.740 ~~0.591~~	per day
~~——~~Instrument-Rated Meters	$ 1.769 ~~1.413~~	per day
~~——~~Primary	$ 5.276 ~~4.214~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Energy Charges

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge	$ 0.00794 ~~0.00794~~	per kWh

Delivery (only one set applies)				
		Summer	Winter	
Secondary	First 5,000 kWh	$ 0.05375 ~~0.04293~~	$ 0.05369 ~~0.04288~~	per kWh
	All additional kWh	$ 0.01728 ~~0.01380~~	$ 0.01679 ~~0.01341~~	per kWh
Primary	First 5,000 kWh	$ 0.04953 ~~0.03956~~	$ 0.04941 ~~0.03946~~	per kWh
	All additional kWh	$ 0.01266 ~~0.01011~~	$ 0.01256 ~~0.01003~~	per kWh

Generation Charges			
	Summer	Winter	
First 5,000 kWh	$ 0.09643 ~~0.07702~~	$ 0.07677 ~~0.06130~~	per kWh
All additional kWh	$ 0.06021 ~~0.04809~~	$ 0.04056 ~~0.03239~~	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
SD-1	School Discount
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.

RATE SCHEDULE E-32 XS D
EXTRA SMALL GENERAL SERVICE
WITH DEMAND (0 kW - 20 kW)

AVAILABILITY

This rate schedule is available to non-residential Customers and to Customers with secondary services at residential sites that are separately metered such as wells or detached garages.

DESCRIPTION

This rate is a General Service rate for Customers with an average summer monthly maximum demand of 20 kW or less per month. This rate has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 1-hour period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges:		
For service through Self-Contained Meters	$ 1.389 ~~1.110~~	per day
For service through Instrument-Rated Meters	$ 2.418 ~~1.932~~	per day
For service at Primary Voltage	$ 5.925 ~~4.733~~	per day

	Summer	Winter	
Secondary Service Demand Charge	$ 8.393 ~~6.686~~	$ 8.393 ~~6.686~~	per kW
Primary Service Demand Charge	$ 5.231 ~~4.167~~	$ 5.231 ~~4.167~~	per kW
Secondary Service Energy Charge	$ 0.12676 ~~0.10266~~	$ 0.10350 ~~0.08414~~	per kWh
Primary Service Energy Charge	$ 0.11949 ~~0.09687~~	$ 0.09646 ~~0.07853~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charges:	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.740 ~~0.591~~	per day
Instrument-Rated Meters	$ 1.769 ~~1.413~~	per day
Primary	$ 5.276 ~~4.214~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Delivery Secondary	$ 8.393 ~~6.686~~	per kW
Delivery Primary	$ 5.231 ~~4.167~~	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge	$ 0.00794 ~~0.00794~~	per kWh

Delivery Charges (only one applies)			
	Summer	Winter	
For Secondary Service	$ 0.01701 ~~0.01355~~	$ 0.01678 ~~0.01337~~	per kWh
For Primary Service	$ 0.00974 ~~0.00776~~	$ 0.00974 ~~0.00776~~	per kWh

	Summer	Winter	
Generation Charge	$ 0.09794 ~~0.07802~~	$ 0.07491 ~~0.05968~~	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 1-hour period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
SD-1	Schools Discount
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedule E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule Time-of-Use E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 3.657 ~~2.891~~	per day
For service through Instrument-Rated Meters	$ 4.687 ~~3.705~~	per day
For service at Primary Voltage	$ 8.195 ~~6.477~~	per day
For service at Transmission Voltage	$ 46.362 ~~36.639~~	per day

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	$ 20.338 ~~16.692~~	per kW
	All additional On-Peak kW	$ 13.505 ~~11.285~~	per kW
	First 100 Off-Peak kW	$ 7.636 ~~6.042~~	per kW
	All additional Off-Peak kW	$ 4.017 ~~3.178~~	per kW
Primary	First 100 On-Peak kW	$ 19.653 ~~16.150~~	per kW
	All additional On-Peak kW	$ 13.401 ~~11.203~~	per kW
	First 100 Off-Peak kW	$ 6.779 ~~5.364~~	per kW
	All additional Off-Peak kW	$ 3.899 ~~3.085~~	per kW
Transmission	First 100 On-Peak kW	$ 18.433 ~~15.185~~	per kW
	All additional On-Peak kW	$ 11.927 ~~10.037~~	per kW
	First 100 Off-Peak kW	$ 5.811 ~~4.598~~	per kW
	All additional Off-Peak kW	$ 3.737 ~~2.957~~	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$ 0.08411 ~~0.06665~~	$ 0.06669 ~~0.05286~~	per kWh
Off-Peak	$ 0.06879 ~~0.05452~~	$ 0.05136 ~~0.04073~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 2.872 ~~2.270~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day

Metering* (only one applies)		
Self-Contained Meters	$ 0.739 ~~0.584~~	per day
Instrument-Rated Meters	$ 1.769 ~~1.398~~	per day
Primary	$ 5.277 ~~4.170~~	per day
Transmission	$ 43.444 ~~34.332~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870 ~~2.870~~	per kW
Generation On-Peak		$ 7.110 ~~5.626~~	per kW
Generation Off-Peak		$ 2.706 ~~2.141~~	per kW
Delivery - Secondary	First 100 On-Peak kW	$ 10.358 ~~8.196~~	per kW
	All additional On-Peak kW	$ 3.525 ~~2.789~~	per kW
	First 100 Off-Peak kW	$ 4.930 ~~3.901~~	per kW
	All additional Off-Peak kW	$ 1.311 ~~1.037~~	per kW
Delivery - Primary	First 100 On-Peak kW	$ 9.673 ~~7.654~~	per kW
	All additional On-Peak kW	$ 3.421 ~~2.707~~	per kW
	First 100 Off-Peak kW	$ 4.073 ~~3.223~~	per kW
	All additional Off-Peak kW	$ 1.193 ~~0.944~~	per kW
Delivery - Transmission	First 100 On-Peak kW	$ 8.453 ~~6.689~~	per kW
	All additional On-Peak kW	$ 1.947 ~~1.541~~	per kW
	First 100 Off-Peak kW	$ 3.105 ~~2.457~~	per kW
	All additional Off-Peak kW	$ 1.031 ~~0.816~~	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387 ~~0.00315~~	per kWh
Delivery Charge	$ 0.01444 ~~0.01143~~	Per kWh

	Summer	Winter	
Generation On-Peak	$ 0.06580 ~~0.05207~~	$ 0.04838 ~~0.03828~~	per kWh
Generation Off-Peak	$ 0.05048 ~~0.03994~~	$ 0.03305 ~~0.02615~~	per kWh

For billing purposes, the On-Peak kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during the On-Peak period during the billing period, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest On-Peak kW measured during the six summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

Off-peak kW will be based on the average kW supplied during the 15-minute period of maximum use during the Off-peak hours of the billing period, as determined from readings of the Company's meter.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of $ (0.00293) ~~(0.00234)~~ per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~7.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.
3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 101 kW up to 400 kW.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 1.389 ~~1.110~~	per day
For service through Instrument-Rated Meters	$ 2.418 ~~1.932~~	per day
For service at Primary Voltage	$ 5.925 ~~4.733~~	per day
For service at Transmission Voltage	$ 44.093 ~~34.851~~	per day

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	$ 21.244 ~~17.493~~	per kW
	All additional On-Peak kW	$ 13.495 ~~11.326~~	per kW
	First 100 Off-Peak kW	$ 8.089 ~~6.438~~	per kW
	All additional Off-Peak kW	$ 3.983 ~~3.170~~	per kW
Primary	First 100 On-Peak kW	$ 20.471 ~~16.878~~	per kW
	All additional On-Peak kW	$ 13.378 ~~11.233~~	per kW
	First 100 Off-Peak kW	$ 7.119 ~~5.666~~	per kW
	All additional Off-Peak kW	$ 3.849 ~~3.064~~	per kW
Transmission	First 100 On-Peak kW	$ 19.085 ~~15.775~~	per kW
	All additional On-Peak kW	$ 12.901 ~~10.853~~	per kW
	First 100 Off-Peak kW	$ 6.021 ~~4.792~~	per kW
	All additional Off-Peak kW	$ 3.670 ~~2.921~~	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$ 0.08623 ~~0.06870~~	$ 0.06968 ~~0.05553~~	per kWh
Off-Peak	$ 0.07170 ~~0.05713~~	$ 0.05513 ~~0.04395~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day

Metering* (only one applies)		
Self Contained Meters	$ 0.740 ~~0.591~~	per day
Instrument-Rated Meters	$ 1.769 ~~1.413~~	per day
Primary	$ 5.276 ~~4.214~~	per day
Transmission	$ 43.444 ~~34.332~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870 ~~2.870~~	per kW
Generation On-Peak		$ 5.863 ~~4.666~~	per kW
Generation Off-Peak		$ 2.231 ~~1.776~~	per kW
Delivery - Secondary	First 100 On-Peak kW	$ 12.511 ~~9.957~~	per kW
	All additional On-Peak kW	$ 4.762 ~~3.790~~	per kW
	First 100 Off-Peak kW	$ 5.858 ~~4.662~~	per kW
	All additional Off-Peak kW	$ 1.752 ~~1.394~~	per kW
Delivery - Primary	First 100 On-Peak kW	$ 11.738 ~~9.342~~	per kW
	All additional On-Peak kW	$ 4.645 ~~3.697~~	per kW
	First 100 Off-Peak kW	$ 4.888 ~~3.890~~	per kW
	All additional Off-Peak kW	$ 1.618 ~~1.288~~	per kW
Delivery - Transmission	First 100 On-Peak kW	$ 10.352 ~~8.239~~	per kW
	All additional On-Peak kW	$ 4.168 ~~3.317~~	per kW
	First 100 Off-Peak kW	$ 3.790 ~~3.016~~	per kW
	All additional Off-Peak kW	$ 1.439 ~~1.145~~	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh
Delivery Charge	$ 0.00372 ~~0.00296~~	per kWh

	Summer	Winter	
Generation On-Peak	$ 0.07864 ~~0.06259~~	$ 0.06209 ~~0.04942~~	per kWh
Generation Off-Peak	$ 0.06411 ~~0.05102~~	$ 0.04754 ~~0.03784~~	per kWh

The kW used to determine the demand charge as shown above will be based on the average kW supplied during the highest 15-minute period during the month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

RATE SCHEDULE E-32TOU S
SMALL GENERAL SERVICE (21 kW - 100 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available to non-residential Customers with a monthly load of 21 kW up to 100 kW.

DESCRIPTION

This rate has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by both season (summer or winter) and the time of day that the energy is used (On-Peak or Off-Peak).

The Company will place the Customer on the applicable Rate Schedule E-32 TOU XS, E-32 TOU S, E-32 TOU M, or E-32 TOU L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer months:	May through October
Winter months:	November through April

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 1.389 ~~1.110~~	per day
For service through Instrument-Rated Meters	$ 2.418 ~~1.932~~	per day
For service at Primary Voltage	$ 5.925 ~~4.733~~	per day

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	$ 23.541 ~~19.372~~	per kW
	All additional On-Peak kW	$ 11.743 ~~9.953~~	per kW
	First 100 Off-Peak kW	$ 9.522 ~~7.601~~	per kW
	All additional Off-Peak kW	$ 3.275 ~~2.614~~	per kW
Primary	First 100 On-Peak kW	$ 22.363 ~~18.431~~	per kW
	All additional On-Peak kW	$ 11.569 ~~9.814~~	per kW
	First 100 Off-Peak kW	$ 8.045 ~~6.422~~	per kW
	All additional Off-Peak kW	$ 3.073 ~~2.453~~	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$ 0.08679 ~~0.06935~~	$ 0.06799 ~~0.05434~~	per kWh
Off-Peak	$ 0.06601 ~~0.05276~~	$ 0.05016 ~~0.04010~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.740 ~~0.591~~	per day
Instrument-Rated Meters	$ 1.769 ~~1.413~~	per day
Primary	$ 5.276 ~~4.214~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$ 2.870 ~~2.870~~	per kW
Generation – Capacity On-Peak		$ 5.185 ~~4.139~~	per kW
Generation – Capacity Off-Peak		$ 1.972 ~~1.574~~	per kW
Delivery - Secondary	First 100 On-Peak kW	$ 15.486 ~~12.363~~	per kW
	All additional On-Peak kW	$ 3.688 ~~2.944~~	per kW
	First 100 Off-Peak kW	$ 7.550 ~~6.027~~	per kW
	All additional Off-Peak kW	$ 1.303 ~~1.040~~	per kW
Delivery - Primary	First 100 On-Peak kW	$ 14.308 ~~11.422~~	per kW
	All additional On-Peak kW	$ 3.514 ~~2.805~~	per kW
	First 100 Off-Peak kW	$ 6.073 ~~4.848~~	per kW
	All additional Off-Peak kW	$ 1.101 ~~0.879~~	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh

	Summer	Winter	
Generation On-Peak	$ 0.08292 ~~0.06620~~	$ 0.06412 ~~0.05119~~	per kWh
Generation Off-Peak	$ 0.06214 ~~0.04961~~	$ 0.04629 ~~0.03695~~	per kWh

The kW used to determine the demand charge as shown will be the Customer's highest 15-minute On-Peak energy used during the billing month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available to non-residential Customers and Customers with secondary services at residential sites that are separately metered such as wells or detached garages. The Customer must have a monthly load of 20 kW or less to be served on this rate schedule.

DESCRIPTION

This rate has three-parts: a basic service charge; a demand charge for the average demand (kW) supplied during the one-hour period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The demand charge may~~will~~ vary by season and the energy charge will vary by both season (summer or winter) and the time of day that the energy is used (On-Peak or Off-Peak).

The Company will place the Customer on the applicable Rate Schedule E-32 TOU XS, E-32 TOU S, E-32 TOU M, or E-32 TOU L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges		
For service through Self-Contained Meters	$ 1.389 ~~1.110~~	per day
For service through Instrument-Rated Meters	$ 2.418 ~~1.932~~	per day
For service at Primary Voltage	$ 5.925 ~~4.733~~	per day

Demand Charges (only one set applies)			
Secondary	On-Peak kW	$ 5.497 ~~4.386~~	per kW
	Off-Peak kW	$ 3.143 ~~2.508~~	per kW
Primary	On-Peak kW	$ 4.775 ~~3.810~~	per kW
	Off-Peak kW	$ 1.890 ~~1.508~~	per kW

Energy Charges (only one set applies)				
		Summer	Winter	
Secondary	On-Peak	$ 0.17871 ~~0.14427~~	$ 0.14248 ~~0.11536~~	per kWh
	Off-Peak	$ 0.13662 ~~0.11068~~	$ 0.10885 ~~0.08852~~	per kWh
Primary	On-Peak	$ 0.17628 ~~0.14233~~	$ 0.14005 ~~0.11342~~	per kWh
	Off-Peak	$ 0.12909 ~~0.10467~~	$ 0.10132 ~~0.08251~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Meter* (only one applies)		
Self-Contained Meters	$ 0.740 ~~0.591~~	per day
Instrument-Rated Meters	$ 1.769 ~~1.413~~	per day
Primary Meters	$ 5.276 ~~4.214~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Delivery Components (only one set applies)			
Secondary	On-Peak kW	$ 1.934 ~~1.543~~	per kW
	Off-Peak kW	$ 1.313 ~~1.048~~	per kW
Primary	On-Peak kW	$ 1.212 ~~0.967~~	per kW
	Off-Peak kW	$ 0.060 ~~0.048~~	per kW

Generation	On-Peak kW	$ 3.563 ~~2.843~~	per kW
	Off-Peak kW	$ 1.830 ~~1.460~~	per kW

Energy Charge Components

System Benefits Charge	$ 0.00387 ~~0.00315~~	per kWh
Transmission Charge	$ 0.00794 ~~0.00794~~	per kWh

Delivery Components (only one set applies)			
Secondary	On-Peak	$ 0.06910 ~~0.05514~~	per kWh
	Off-Peak	$ 0.04390 ~~0.03503~~	per kWh
Primary	On-Peak	$ 0.06667 ~~0.05320~~	per kWh
	Off-Peak	$ 0.03637 ~~0.02902~~	per kWh

	Summer	Winter	
Generation On-Peak	$ 0.09780 ~~0.07804~~	$ 0.06157 ~~0.04913~~	per kWh
Generation Off-Peak	$ 0.08091 ~~0.06456~~	$ 0.05314 ~~0.04240~~	per kWh

The kW used to determine the demand charge as shown above will be the Customer's highest one-hour On-Peak and Off-Peak energy used during the billing month.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
SD-1	Schools Discount
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to Customers whose monthly maximum demand registers 3,000 kW or more for 3 consecutive months, over the prior 12 months.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period of maximum use during the month, and an energy charge for the total energy (kWh) used for the entire month.

CHARGES

The monthly bill will be calculated with the following charges plus adjustments. A Customer's charge will depend on the voltage of their service connection.

Bundled Charges

Customers Served at Secondary Voltage		
Basic Service Charge for Self-Contained Meters	$ 5.156 ~~4.033~~	per day
Basic Service Charge for Instrument-Rated Meters	$ 6.159 ~~4.818~~	per day
Demand Charge	$ 25.216 ~~20.432~~	per kW
Energy Charge	$ 0.04714 ~~0.03700~~	per kWh

Customers Served at Primary Voltage		
Basic Service Charge	$ 9.573 ~~7.489~~	per day
Demand Charge	$ 23.682 ~~19.232~~	per kW
Energy Charge	$ 0.04714 ~~0.03700~~	per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$ 46.732 ~~36.560~~	per day
Demand Charge	$ 16.114 ~~13.311~~	per kW
Energy Charge	$ 0.04714 ~~0.03700~~	per kWh

Eligible Military Base Customers		
Basic Service Charge	$ 9.573 ~~7.489~~	per day
Demand Charge	$ 17.219 ~~14.176~~	per kW
Energy Charge	$ 0.04714 ~~0.03700~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 4.388 ~~3.433~~	per day
Meter Reading	$ 0.012 ~~0.009~~	per day
Billing	$ 0.036 ~~0.028~~	per day
Meter (only one applies)		
Self-Contained Meter	$ 0.720 ~~0.563~~	per day
Instrument-Rated Meter	$ 1.723 ~~1.348~~	per day
Primary Meter	$ 5.137 ~~4.019~~	per day
Transmission Meter	$ 42.296 ~~33.090~~	per day
Demand Charge Components		
Generation	$ 12.429 ~~9.724~~	per kW
Transmission	$ 3.236 ~~3.236~~	per kW
Delivery (only one applies)		
Secondary Service	$ 9.551 ~~7.472~~	per kW
Primary Service	$ 8.017 ~~6.272~~	per kW
Transmission Service	$ 0.449 ~~0.351~~	per kW
Eligible Military Base	$ 1.554 ~~1.216~~	per kW
Energy Charge Components		
Generation	$ 0.04327 ~~0.03385~~	per kWh
System Benefits	$ 0.00387 ~~0.00315~~	per kWh

The kW for billing will be the greater of:

a. The average kW supplied during the 15-minute period of maximum use during the monthly billing period; or

b. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

c. The minimum kW specified in a service agreement. A time period other than 15 minutes can be specified in a service agreement.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~6.~~5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~7.~~6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
E-56	Partial requirements – General
E-56R	Partial requirements – Renewable
EPR-2	Partial requirements – Net billing
EPR-6	Partial Requirements – Net Metering
GPS-1, GPS-2, GPS-3	Green Power
IRR	Interruptible program
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. Service under this schedule is generally provided at secondary voltage. When the Customer owns the distribution transformer(s) service is provided at primary voltage.

2. The type of service provided under this schedule will be three-phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

3. Daily metering charges apply to typical installations. Customers requiring specialized equipment may incur additional metering charges that reflect the additional cost.

4. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the partial requirement rate riders.

5. Some Customers will have a service agreement that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges and other service details. This typically includes Customers taking service at primary or transmission level voltage and those on various special rates and programs.

6. Eligible military base refers to a military base receiving service at a primary voltage and served from a dedicated distribution feeder.

7. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

8. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

9. This schedule is not applicable to breakdown, standby, supplemental, residential, or resale service.

10. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

AVAILABILITY

This rate schedule is available to Customers whose monthly maximum demand registers 3,000 kW or more for 3 consecutive months, over the prior 12 months.

DESCRIPTION

This rate has three parts: a basic service charge, a demand (kW) charge, and an energy charge for the energy (kWh) used for the entire month. Both the demand charge and the energy charge will vary by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

On-Peak hours	11:00 a.m. - 9:00 p.m. Monday through Friday
Off-Peak hours	All remaining hours

CHARGES

The monthly bill will be calculated at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Service

Customers Served at Secondary Voltage		
Basic Service Charge for Self-Contained Meters	$ 5.156 ~~4.033~~	per day
Basic Service Charge for Instrument-Rated Meters	$ 6.159 ~~4.818~~	per day
Demand Charge On-Peak	$ 21.544 ~~17.559~~	per kW
Demand Charge Off-Peak	$ 3.401 ~~2.661~~	per kW
Energy Charge On-Peak	$ 0.05189 ~~0.04072~~	per kWh
Energy Charge Off-Peak	$ 0.04125 ~~0.03239~~	per kWh

Customers Served at Primary Voltage		
Basic Service Charge	$ 9.573 ~~7.489~~	per day
Demand Charge On-Peak	$ 20.073 ~~16.408~~	per kW
Demand Charge Off-Peak	$ 3.254 ~~2.546~~	per kW
Energy Charge On-Peak	$ 0.05189 ~~0.04072~~	per kWh
Energy Charge Off-Peak	$ 0.04125 ~~0.03239~~	Per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$ 46.732 ~~36.560~~	per day
Demand Charge On-Peak	$ 12.470 ~~10.460~~	per kW
Demand Charge Off-Peak	$ 2.492 ~~1.950~~	per kW
Energy Charge On-Peak	$ 0.05189 ~~0.04072~~	per kWh
Energy Charge Off-Peak	$ 0.04125 ~~0.03239~~	Per kWh

Eligible Military Base Customers		
Basic Service Charge	$ 9.573 ~~7.489~~	per day
Demand Charge On-Peak	$ 14.513 ~~12.058~~	per kW
Demand Charge Off-Peak	$ 2.696 ~~2.109~~	per kW
Energy Charge On-Peak	$ 0.05189 ~~0.04072~~	per kWh
Energy Charge Off-Peak	$ 0.04125 ~~0.03239~~	Per kWh

Unbundled Standard Offer Service

Bundled Charges consists of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 4.388 ~~3.433~~	per day
Meter Reading	$ 0.012 ~~0.009~~	per day
Billing	$ 0.036 ~~0.028~~	per day
Meter (only one applies)		
Self-Contained Meter	$ 0.720 ~~0.563~~	per day
Instrument-Rated Meters	$ 1.723 ~~1.348~~	per day
Primary Meter	$ 5.137 ~~4.019~~	per day
Transmission Meter	$ 42.296 ~~33.090~~	per day
Demand Charge Components		
Transmission Charge On-Peak	$ 3.236 ~~3.236~~	per kW
Generation Charge On-Peak	$ 8.558 ~~6.695~~	per kW
Generation Charge Off-Peak	$ 2.426 ~~1.898~~	per kW

Delivery (only one set of charges applies)			
Secondary	On-Peak	$ 9.750 ~~7.628~~	per kW
	Off-Peak	$ 0.975 ~~0.763~~	per kW
Primary	On-Peak	$ 8.279 ~~6.477~~	per kW
	Off-Peak	$ 0.828 ~~0.648~~	per kW
Transmission	On-Peak	$ 0.676 ~~0.529~~	per kW
	Off-Peak	$ 0.066 ~~0.052~~	per kW
Eligible Military Bases	On-Peak	$ 2.719 ~~2.127~~	per kW
	Off-Peak	$ 0.270 ~~0.211~~	per kW
Energy Charge Components			
Generation On-Peak		$ 0.04802 ~~0.03757~~	per kWh
Generation Off-Peak		$ 0.03738 ~~0.02924~~	per kWh
System Benefits		$ 0.00387 ~~0.00315~~	per kWh

MINIMUM BILL

The bill will not be less than the Basic Service Charge plus the Demand Charge for the minimum kW specified in the Customer's service agreement or contract.

For billing kW purposes:

a. The On-Peak is based on the greater of the following:

   i. The average kW supplied during the 15-minute period of maximum use during the billing period; or

   ii. 80% of the highest On-Peak kW measured during May through October of the twelve months ending with the current month.

b. Off-Peak is based on the average kW supplied during the 15-minute period of maximum use during Off-Peak hours.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~6.~~5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~7.~~6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
E-56R	Partial requirements – Renewable
EPR-2	Partial requirements – Net billing
EPR-6	Partial Requirements – Net Metering
GPS-1, GPS-2, GPS-3	Green Power
IRR	Interruptible program
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.
2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not~~t~~ meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. Service under this schedule is generally provided at secondary voltage. When the Customer owns the distribution transformer(s) service is provided at primary voltage.

2. The type of service provided under this schedule will be three-phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

3. Daily metering charges apply to typical installations. Customers requiring specialized Equipment may incur additional metering charges that reflect the additional cost.

4. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the partial requirement rate riders.

5. Some Customers will have a service agreement or contract that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges, and other service details.

6. Eligible military base refers to a military base receiving service at a primary voltage and served from a dedicated distribution feeder.

7. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

8. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

9. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

10. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

AVAILABILITY

This rate schedule is available to Customers: (i) whose monthly maximum demand is 5,000 kW or more; (ii) with a load factor of 92% or more for a minimum of nine months of the prior 12 month period; and (iii) where the Customer also seeks the Economic Development and Sustainability features described below, the Customer must also meet a monthly demand of 15,000 kW, and the 50% Carbon Free Activity requirement set out in this rate schedule.

Customers will be required to execute an Electric Supply Agreement (ESA) that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges, and other service details, including maintenance.

Customers with monthly demands of 15,000 kW or greater may choose to be served with transmission level service by providing the Company with a contribution in aid of construction (CIAC) in lieu of purchasing transmission level facilities. For new Customers, this will be addressed in their Line Extension Agreement pursuant to Service Schedule 3. The Customer will be required to execute a maintenance contract and share in the cost of replacement facilities. Under this option, the Company may also finance the CIAC at the Company's weighted average cost of capital established in its most recent rate case. This financing period will not exceed 10 years.

50% CARBON FREE ACTIVITY REQUIREMENT AND SUSTAINABILITY FEATURES

In addition to having a monthly demand of at least 15,000 kW and having a load factor of 92%, a Customer within the Company's service territory seeking to manage sustainability goals, must demonstrate that it is carbon free for at least 50% of its energy consumption on an annual basis within APS territory. The 50% requirement can be met through Renewable Energy Credits, Carbon Credits, carbon offsets or demonstrated improvement in Carbon Free Activity, and will be specified in the Customer's ESA with the Company. Carbon Free Activities are load shifting, new load added during carbon free curtailment periods, advancements in electrification, energy storage or electric vehicle charging during carbon free curtailment periods.

The Economic Development and Sustainability features below will be limited to an additional 50 MW of load annually per Customer and will not exceed 500 MW in total Customer load unless there is sufficient long-term market liquidity to do so, as determined by APS in its sole discretion. APS will evaluate long-term market liquidity with Customer's receiving service under this rate schedule at least once per year.

DESCRIPTION

This rate has three parts: a basic service charge, a demand (kW) charge consisting of the average kW supplied during the 15-minute period of maximum use during the billing period, and an energy (kWh) charge for the energy used for the entire month.

Monthly load factor will be established using the formula:

Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

CHARGES

The monthly bill will be calculated at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Service

Customers Served at Secondary Voltage		
Basic Service Charge	$ 6.159 ~~4.818~~	per day
Demand Charge	$ 20.643 ~~16.989~~	per kW
Energy Charge	$ 0.04416 ~~0.03498~~	per kWh

Customers Served at Primary Voltage		
Basic Service Charge	$ 9.573 ~~7.489~~	per day
Demand Charge	$ 19.056 ~~15.735~~	per kW
Energy Charge	$ 0.04416 ~~0.03498~~	per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$ 46.732 ~~36.560~~	per day
Demand Charge	$ 14.688 ~~12.284~~	per kW
Energy Charge	$ 0.04416 ~~0.03498~~	per kWh

Unbundled Standard Offer Service

Bundled Charges consists of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 4.388 ~~3.433~~	per day
Meter Reading	$ 0.012 ~~0.009~~	per day
Billing	$ 0.036 ~~0.028~~	per day
Meter (only one applies)		
Instrument-Rated Meter	$ 1.723 ~~1.348~~	per day
Primary Meter	$ 5.137 ~~4.019~~	per day
Transmission Meter	$ 42.296 ~~33.090~~	per day
Demand Charge Components		
Transmission Charge	$ 3.236 ~~3.236~~	per kW
Generation - Capacity	$ 10.971 ~~8.668~~	per kW
Delivery (only one applies)		
Secondary Service	$ 6.436 ~~5.085~~	per kW
Primary Service	$ 4.849 ~~3.831~~	per kW
Transmission Service	$ 0.481 ~~0.380~~	per kW
Energy Charge Components		
Generation - Fuel	$ 0.04029 ~~0.03183~~	per kWh
System Benefits	$ 0.00387 ~~0.00315~~	per kWh

The kW for billing will be the greater of:

a. The average kW supplied during the 15-minute period of maximum use during the monthly billing period; or

b. The minimum kW specified in a service agreement.

MINIMUM BILL

The bill will not be less than the minimum amount specified in the Customer's service agreement or contract.

ECONOMIC DEVELOPMENT AND SUSTAINABILITY

Qualifying Customers will be eligible for one or more of the following additional features:

1. The "Generation – Fuel" and "Power Supply Adjustment Charges" may be replaced with a loss adjusted market proxy index price using the Intercontinental Exchange (ICE) day-ahead on and off-peak prices for the Palo Verde hub, or successor index, plus a non-bypassable fuel cost and administrative fee of $0.~~00270~~ 00342 per kWh. In any billing cycle, the combined average of the on and off-peak market proxy index price shall not be less than zero.

2. An Economic Development discount, for new load only, not to exceed 35% on the bundled or unbundled "Generation – Capacity" charge referenced above for a period not to exceed six years. Such terms and date for implementation of the discount will be specified in the Customer's ESA with the Company, based on an evaluation of criteria as described in the Company's Service Schedule 9.

3. A "Generation – Capacity" Credit denominated on a dollar per kW basis for providing APS the ability to remove the load from APS's system through a microgrid, battery or otherwise that provides APS sufficient flexible control of the Customer's load on APS's system. The Credit will be based on a resource planning analysis and will be specified in the Customer's ESA with the Company. The sum of the Economic Development discount and Generation Capacity Credit shall not exceed the "Generation – Capacity" charge specified in this Rate Schedule XHLF. To the extent a Customer is otherwise receiving a capacity credit from the Company, the capacity generating this credit is not also eligible for the "Generation – Capacity" credit described herein.

4. If a Customer fails to meet a 92% load factor in a particular billing cycle solely due to load growth within that billing cycle, the billing cycle will not count against the Customer's compliance with the load factor provisions in this Rate Schedule XHLF.

5. If a Customer meets its carbon free demonstration through renewable resources under its ownership or control, the Customer may not schedule energy into the Company's service territory to self supply energy.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1, unless the Customer has demonstrated its 50% carbon free commitment described above. Customer loads for Customers who have demonstrated their carbon free commitment will not be included in APS's load for purposes of determining achievement of the Commission's Renewable Energy Standard. This provision will be reviewed if the Commission's Renewable Energy Standards are modified or replaced.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1, unless the Customer has selected the loss adjusted market proxy index price mechanism.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1. This will be set out in the ESA.

~~6.~~5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~7.~~6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenue, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

GPS-1, GPS-2, GPS-3	Green Power

Qualifying Customers taking service under the Economic Development and Sustainability provisions of this rate schedule are not eligible for rate riders GPS-1, GPS-2, or GPS-3.

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. The type of service provided under this schedule will be three-phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

2. Daily metering charges apply to typical installations. Customers requiring specialized Equipment may incur additional metering charges that reflect the additional cost.

3. Customers that self-provide some of their electrical requirements from primary on-site generation will be billed according to one of the partial requirement rate riders.

4. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

5. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

6. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this Schedule, but are not eligible for the Economic Development and Sustainability features. The bill for these Customers will only include the Unbundled

Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by the Company and billed to the Customer at the charges shown above.

7. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

AVAILABILITY

This rate schedule is applicable to non-taxable religious houses of worship.

The Company may request a copy of the Internal Revenue Service letter in which the Customer's non-taxable status as a religious organization is determined. Customers also agree to provide the Company a copy of any Internal Revenue Service letter which changes or supersedes that tax status determination.

DESCRIPTION

This rate schedule is specifically for places of worship. It is only available to the actual sanctuary or principal place of worship, and does not apply to separate or combined facilities such as kitchens or meeting rooms.

This rate has three parts: a basic service charge, a demand charge, and an energy charge. The energy charge will vary by season (summer or winter) and both the demand and energy charge will vary by the time of day that the energy is used (On-Peak or Off-Peak).

TIME PERIODS

On-Peak hours:	11:00 a.m. to 9:00 p.m. Monday through Friday.
Off-Peak hours:	All remaining hours.
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$ 2.418 ~~1.932~~	per day

Demand and Energy Charges			
	Summer	Winter	
On-Peak Demand Charge	$ 4.008 ~~3.762~~	$ 4.008 ~~3.762~~	per kW
Off-Peak Excess Demand Charge	$ 2.935 ~~2.301~~	$ 2.935 ~~2.301~~	per kW
On-Peak Energy Charge:	$ 0.18924 ~~0.14849~~	$ 0.16689 ~~0.13097~~	per kWh
Off-Peak Energy Charge:	$ 0.09244 ~~0.07259~~	$ 0.08304 ~~0.06522~~	per kWh

In the event Off-Peak kW usage is greater than twice the highest On-Peak kW usage in a month, the difference between the Off-Peak kW usage and twice the On-Peak kW usage will be billed at the Off-Peak Excess Demand Charge. Total On-Peak kW usage for the month will also be billed as shown above.

For billing purposes, the kW used in this rate schedule is based on the average kW used during the 15-minute period of maximum use during the On-Peak period and the Off-Peak period during the month.

Unbundled Standard Offer Service

Bundled Charges consist of the Components shown below. These are not additional charges.

Basic Service Charges		
Customer Accounts	$ 0.603 ~~0.482~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Metering	$ 1.769 ~~1.413~~	per day

Demand Charges		
Transmission Charge On-Peak	$ 2.870 ~~2.870~~	per kW
Delivery Charge On-Peak	$ 1.138 ~~0.892~~	per kW
Delivery Charge Excess Off-Peak	$ 2.935 ~~2.301~~	per kW

Energy Charges			
	Summer	Winter	
Generation On-Peak	$ 0.13888 ~~0.10889~~	$ 0.11653 ~~0.09137~~	per kWh
Generation Off-Peak	$ 0.04208 ~~0.03299~~	$ 0.03268 ~~0.02562~~	per kWh
Delivery	$ 0.04649 ~~0.03645~~	$ 0.04649 ~~0.03645~~	per kWh
System Benefits	$ 0.00387 ~~0.00315~~	$ 0.00387 ~~0.00315~~	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

5. This rate schedule is not available to service for which Rate Schedules E-34 or E-35 is applicable.

6. Direct Access Customers are not eligible for this rate schedule.

AVAILABILITY

This rate schedule is for a pilot rate available only to non-residential Customers that:

a. have average summer monthly loads of 401 kW and greater;
b. do not qualify for Rate Schedules E-34 or E-35;
c. are not taking service under rate rider AG-X or through Direct Access; and
d. operate a chemical, mechanical, or thermal energy storage system located on their premises.

This rate schedule will be capped at a peak demand total of 35,000 kW of installed systems and active interconnection applications, on a first-come first-served basis. Availability of this rate is subject to the availability of required metering equipment and completion of necessary enhancements to the Company's billing system.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The demand and energy charges vary by season (summer or non-summer) and time of day (On-Peak, Remaining, and Off-Peak).

If Customer no longer meets the requirements of this rate schedule, the Company will place the Customer on the applicable Time-of-Use Rate Schedule (E-32TOU XS, E-32 TOU S, E-32 TOU M, E-32 TOU L) based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer Hours	
On-Peak hours:	4:00 pm – 7:00 pm weekdays
Remaining hours:	11:00 am – 4:00 pm and 7:00 pm - 11:00 pm weekdays; 11:00 am – 11:00 pm weekends
Off-Peak hours:	All remaining hours
Non-Summer Hours	
On-Peak hours:	4:00 pm – 7:00 pm weekdays
Remaining hours:	6:00 am – 10:00 am, 3:00 pm - 4:00 pm and 7:00 pm - 11:00 pm weekdays; 6:00 am – 10:00 am and 3:00 pm – 11:00 pm weekends
Off-Peak hours:	All remaining hours

Summer season:	Calendar months June 1st through September 30th
Non-Summer season:	Calendar months October 1st through May 31st

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 3.657 ~~2.891~~	per day
For service through Instrument-Rated Meters	$ 4.687 ~~3.705~~	per day
For service at Primary Voltage	$ 8.195 ~~6.477~~	per day
For service at Transmission Voltage	$ 46.362 ~~36.639~~	per day

Demand Charges (only one set applies)			
Secondary	Summer On-Peak kW	$ 15.251 ~~12.654~~	per kW
	Summer Remaining-Peak kW	$ 4.762 ~~3.763~~	per kW
	Non-Summer On-Peak kW	$ 13.688 ~~11.419~~	per kW
	Non-Summer Remaining-Peak kW	$ 4.161 ~~3.288~~	per kW
Primary	Summer On-Peak kW	$ 14.208 ~~11.830~~	per kW
	Summer Remaining-Peak kW	$ 4.361 ~~3.446~~	per kW
	Non-Summer On-Peak kW	$ 12.646 ~~10.595~~	per kW
	Non-Summer Remaining-Peak kW	$ 3.760 ~~2.971~~	per kW

Transmission	Summer On-Peak kW	$ 12.126 ~~10.184~~	per kW
	Summer Remaining-Peak kW	$ 3.560 ~~2.813~~	per kW
	Non-Summer On-Peak kW	$ 10.563 ~~8.949~~	per kW
	Non-Summer Remaining-Peak kW	$ 2.959 ~~2.338~~	per kW

Energy Charges			
	Summer	Non-Summer	
On-Peak	$ 0.08255 ~~0.06534~~	$ 0.06539 ~~0.05178~~	per kWh
Remaining	$ 0.07818 ~~0.06189~~	$ 0.06246 ~~0.04946~~	per kWh
Off-Peak	$ 0.07090 ~~0.05613~~	$ 0.05475 ~~0.04337~~	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 2.872 ~~2.270~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.739 ~~0.584~~	per day
Instrument-Rated Meters	$ 1.769 ~~1.398~~	per day
Primary	$ 5.277 ~~4.170~~	per day
Transmission	$ 43.444 ~~34.332~~	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission On-Peak		$ 2.870 ~~2.870~~	per kW
Generation On-Peak		$ 5.367 ~~4.241~~	per kW
Generation Remaining-Peak		$ 2.064 ~~1.631~~	per kW
Delivery - Secondary	Summer On-Peak kW	$ 7.014 ~~5.543~~	per kW
	Summer Remaining-Peak kW	$ 2.698 ~~2.132~~	per kW
	Non-Summer On-Peak kW	$ 5.451 ~~4.308~~	per kW
	Non-Summer Remaining-Peak kW	$ 2.097 ~~1.657~~	per kW
Delivery - Primary	Summer On-Peak kW	$ 5.971 ~~4.719~~	per kW
	Summer Remaining -Peak kW	$ 2.297 ~~1.815~~	per kW
	Non-Summer On-Peak kW	$ 4.409 ~~3.484~~	per kW
	Non-Summer Remaining-Peak kW	$ 1.696 ~~1.340~~	per kW
Delivery - Transmission	Summer On-Peak kW	$ 3.889 ~~3.073~~	per kW
	Summer Remaining-Peak kW	$ 1.496 ~~1.182~~	per kW
	Non-Summer On-Peak kW	$ 2.326 ~~1.838~~	per kW
	Non-Summer Remaining-Peak kW	$ 0.895 ~~0.707~~	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00387 ~~0.00316~~	per kWh
Delivery Charge	$ 0.012790~~.01011~~	Per kWh

	Summer	Non-Summer	
Generation On-Peak	$ 0.06589 ~~0.05207~~	$ 0.04873 ~~0.03851~~	per kWh
Generation Remaining	$ 0.06152 ~~0.04862~~	$ 0.04580 ~~0.03619~~	per kWh
Generation Off-Peak	$ 0.05424 ~~0.04286~~	$ 0.03809 ~~0.03010~~	per kWh

For billing demand purposes, the On-Peak and Remaining hours kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during the On-Peak and Remaining hours during each respective billing period, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8;

2. The minimum kW specified in the agreement for service or individual contract; or

3. 300 kW.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

Summer Billing Season:	June through September billing cycles
Non-Summer Billing Season:	October through May billing cycles

Seasonal billing charges will be applied to customer bills by monthly bill cycle. To the extent a billing cycle overlaps with a change in season under Time Period specified above, all usage during that billing cycle will be charged at the seasonal rates in effect at the time of that billing cycle.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~7.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. At the Company's option Customer will be required to sign the Company's standard agreement for service. If additional construction is required to serve the Customer, the contract period will be five years. If no additional distribution construction is required to serve the Customer, the contract period will be two years. At the end of these two-year service agreements, a Customer may request to modify the minimum kW in the standard agreement for service to reflect the Customer's actual usage during those two years.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for start-up and/or auxiliary load requirements for generation plants with a Power Supply capacity requirement of greater than 3 MW. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual Customer contract. This rate schedule may be used in conjunction with other applicable Company rate schedules; however, any service under this schedule is not eligible for Direct Access.

TYPE OF SERVICE

The type of service provided under this rate schedule shall be three-phase, 60 Hertz, at one standard voltage available within the vicinity of the Customer's site.

CHARGES

The bill will be the sum of the Basic Service Charge, Metering Service, Capacity Rate, and Power Supply Service below, including any applicable adjustments:

Basic Service Charge	$ 8,911.48 ~~7,252.78~~	per month

Metering Service

The monthly metering charge will be 1.29% of the total metering cost specified in the Electric Supply Agreement between the Company and the Customer. This percentage will be reduced to 0.35% when the Customer provides all necessary metering equipment and is responsible for its replacement. The Customer will also be responsible for all applicable costs associated with communications facilities used to compile metered usage information.

Capacity Rate (only one applies)		
Secondary Voltage	$ 6.693 ~~5.447~~	per kW
Primary Voltage	$ 6.457 ~~5.255~~	per kW
Transmission Voltage	$ 2.090 ~~1.701~~	per kW

Power Supply		
Hourly Pricing Proxy at the time of Station use		per kWh
Ancillary Service	$ 0.00074 ~~0.00060~~	per kWh

CONTRACT PERIOD

Any applicable contract periods will be set forth in an Electric Supply Agreement between the Customer and the Company.

CONNECTION COSTS

The Customer will pay all applicable connection costs and system improvement costs not otherwise covered in this schedule as a non-refundable contribution in aid of construction, including any associated tax liability.

POWER SUPPLY CAPACITY

Power Supply Capacity kW will be defined as the greater of:

(a) The amount of capacity (kW) reserved by the Customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of the Customer's generation unit(s) plus any necessary auxiliary load (including generation auxiliary load and/or any other load requirements at the plant site that would otherwise be provided by the Customer when the generation unit(s) are running).

If more than one generation unit is present at a single site, the Electric Supply Agreement may, at the Company's option, allow the Customer to start one unit at a time. In this instance, Power Supply Capacity kW will be defined as the greater of:

(a) The amount of capacity (kW) reserved by the Customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of one and only one Customer generation unit at any given time plus any necessary auxiliary load (including any or all generation auxiliary load and/or any other load requirements at the entire plant site that

would otherwise be provided by the Customer when any or all generation unit(s) are running).

If, during any one billing period, the highest 15 minute measured kW supplied by the Company (by voltage level) exceeds the amount of Power Supply Capacity specified in the Electric Supply Agreement, the Power Supply Capacity reservation (by voltage level) will be permanently increased to equal the higher measured kW. If the Company incurs additional connection costs to provide this added capacity, the Customer is responsible for payment of these costs as specified herein.

DETERMINATION OF HOURLY PRICING PROXY

Hourly pricing proxy will be calculated using the Palo Verde Peak or Off-Peak Intercontinental Exchange ("ICE") ~~published~~ day ahead ~~Dow Jones Electricity~~ Price Index or successor. APS will calculate a weighted average using the day ahead hub pricing and volumes at Palo Verde, Four Corners, and Mead, for firm on-peak and off-peak prices as expressed on a per kWh basis, at the time Station Use power is supplied to the Customer.

METERING

The Company will normally install a supply meter at the point of delivery to the Customer and a generator meter(s) at the point(s) of output from each of the Customer's generators. However, the Customer can elect to supply this metering as long as it conforms to Company specifications. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by the Company.

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

3. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

4. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

5. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

INTERCONNECTION REQUIREMENTS

The Customer must meet all interconnection requirements as determined by the Company. The Customer is responsible for all costs associated with interconnection of the Customer's generation facility to the Company's system.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the Customer's bill. In addition, service may be subject to special terms and conditions as provided for in a Customer contract or service agreement.

AVAILABILITY

This rate schedule is applicable to Customers for Dusk to Dawn lighting for service to be rendered after December 1, 2021.

DESCRIPTION

The E-45 rate is available to Customers with Dusk to Dawn lights. These lights are on the Customer's property or a private street and the Customer is charged a monthly fee for the light. This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company.

TIME PERIOD

Dusk: Time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off the lights.

CHARGES

The monthly bill will consist of the fixture and energy charges, plus adjustments:

I. FIXTURES (Includes Mounting Arm, if applicable)

Fixture Equipment Class	Fixture Cost Range (per unit)	Company Owned Monthly Rate	Customer Owned Monthly Rate
A	$ 1 - $ 430	$ 6.61~~5.72~~	$ 0.13~~0.11~~
B	$ 431 - $ 520	$ 8.05~~6.97~~	$ 0.15~~0.13~~
C	$ 521 - $ 640	$ 9.66~~8.36~~	$ 0.17~~0.15~~
D	$ 641 - $ 820	$ 11.54~~9.99~~	$ 0.22~~0.19~~
E	$ 821 - $ 910	$ 14.60~~12.64~~	$ 0.24~~0.21~~
F	$ 911 - $ 1,010	$ 16.25~~14.07~~	$ 0.27~~0.23~~
G	$ 1,011 - $ 1,110	$ 17.77~~15.38~~	$ 0.28~~0.24~~
H	$ 1,111 - $ 1,250	$ 20.15~~17.44~~	$ 0.30~~0.26~~
I	$ 1,251 - $ 1,520	$ 22.41~~19.40~~	$ 0.36~~0.31~~
J	$ 1,521 - $ 1,670	$ 27.32~~23.65~~	$ 0.39~~0.34~~
K	$ 1,671 - $ 1,850	$ 30.37~~26.29~~	$ 0.44~~0.38~~

Note: Equipment cost greater than $ 1,850 shall be Customer Owned.

II. ENERGY (Includes Generation, T&D, RCS & SBC)

Monthly energy charges for new lighting fixtures will be determined by the Company using the following method:

kWh = Fixture Wattage x 344 Usage Hours
Generation = kWh per month x $ 0.07648~~0.06621~~
T&D, RCS, System Benefits = kWh per month x $ 0.03098~~0.02682~~

NOTES:

1. Company Owned fixtures are those fixtures that the Company installs, owns, maintains, and operates.

2. Customer Owned fixtures are those fixtures where the Customer owns and maintains the lighting fixtures, and the Company approves the installation and operates the fixtures.

3. APS has adopted LED lighting technology ~~as its standard lighting technology,~~ and LED lights do not include replaceable lamps ~~induction lights are also a standard offering"~~ (High Pressure Sodium Lights "HPS" were discontinued by most manufacturers).

4. Listed kWh reflects the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

5. kWh is determined by the company based on the rated wattage of the equipment and an established average hourly usage per month.

III. POLES

				CHARGES
			Height	Company Owned
A. Anchor Base Mounted	Round Steel	1 Simplex Adapter	12 ft.	$ 14.8312.84
			22 ft.	$ 16.6914.45
			25 ft	$ 18.0715.64
			30 ft	$ 20.7517.96
			32 ft	$ 21.8018.87
	Round Steel	2 Simplex Adapters	12 ft.	$ 15.8113.69
			22 ft.	$ 18.1715.73
			25 ft.	$ 18.9616.41
			30 ft.	$ 22.0319.07
			32 ft.	$ 23.4920.34
	Square Steel	5"	13 ft.	$ 17.0014.72
			15 ft.	$ 15.1913.15
			23 ft.	$ 18.0215.60
			25 ft.	$ 19.8117.15
			28 ft.	$ 21.9919.04
			32 ft.	$ 21.8718.93
	Concrete		12 ft.	$ 50.6743.87
	Fiberglass		12 ft.	$ 42.9137.15
	Decorative Transit	4"	16 ft.	$ 41.8436.22
	Decorative Transit	6"	30 ft.	$ 80.7869.93
	Hinged	Square	15 ft.	$ 16.0813.92
		Round	19 ft.	$ 14.5412.59
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$ 14.2712.35
			22 ft.	$ 16.1413.97
			25 ft.	$ 17.4915.14
			30 ft.	$ 20.1917.48
			32 ft.	$ 21.2218.37
	Round Steel	2 Simplex Adapters	12 ft.	$ 15.2413.19
			22 ft.	$ 17.0314.74
			25 ft.	$ 18.3815.91
			30 ft.	$ 21.4618.58
			32 ft.	$ 22.9219.84
		3 Bolt	32 ft.	$ 26.3422.80
	Square Steel	5"	13 ft.	$ 16.4514.24
			15 ft.	$ 16.8214.56
			23 ft.	$ 17.4515.11
			25 ft.	$ 19.2616.67
			28 ft.	$ 21.3918.52
			32 ft.	$ 22.2119.23

III. POLES (cont.)

				CHARGES
			Height	Company Owned
C. Direct Bury	Round Steel		19 ft.	$ 22.44~~19.43~~
			30 ft.	$ 17.52~~15.17~~
			38 ft.	$ 21.38~~18.51~~
		Self-Support	40 ft.	$ 26.34~~22.80~~
		Stepped	25 ft.	$ 60.59~~52.45~~
			32 ft.	$ 63.81~~55.24~~
			49 ft.	$ 79.21~~68.57~~
	Square Steel	4"	34 ft.	$ 19.34~~16.74~~
		5"	20 ft.	$ 18.37~~15.90~~
			30 ft.	$ 19.14~~16.57~~
			38 ft.	$ 20.77~~17.98~~
		8"	28 ft.	$ 34.66~~30.01~~
			32 ft.	$ 36.24~~31.37~~
	Decorative Transit		41 ft. 6 in.	$ 24.95~~21.60~~
	Decorative Transit		47 ft.	$ 31.08~~26.91~~
	Steel Distribution Pole (for lighting)		35 ft.	$ 28.69~~24.84~~
D. Post Top	Decorative Transit Anchor		16 ft.	$ 42.74~~37.00~~
	Gray Steel/Fiberglass		23 ft.	$ 14.82~~12.83~~
	Black Steel		23 ft.	$ 16.33~~14.14~~
E. Wood	Wood Poles		30 ft.	$ 10.90
			35 ft.	$ 10.90
			40 ft.	$ 15.52

NOTES:

1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.

2. Monthly charges for all new Company Owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary line if Customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in Section V below.

3. When adding lighting fixtures to an existing Company Owned or Customer Owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified in Section V below.

IV. ANCHOR BASE

			CHARGES
		Height	Company Owned
A. Flush		4 ft.	$ 12.07~~10.45~~
		6 ft.	$ 14.40~~12.47~~
B. Pedestal		8 ft.	$ 16.51~~14.29~~
	For 32' Round Steel Pole only	4 ft. 6"	$ 11.45~~9.91~~

V. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	CHARGE
	Company Owned
1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire, if Customer provides earthwork and conduit.	$ 4.26~~3.69~~

VI. DETERMINATION OF CHARGES FOR NEW EQUIPMENT

Monthly charges for new lighting fixtures, poles and other equipment will be determined by the Company using the installed equipment multiplied by a monthly fixed charge rate specified in Section I or Section II above.

Any maintenance costs not designated within the E-45 Rate Schedule will be outlined in a maintenance agreement executed between the Company and the Customer.

TRIP CHARGE

A $ 150.00 trip charge per light will be charged when a Customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their dusk to dawn equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM

~~7.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. The Customer is not authorized to make connections to the lighting circuits or to make attachments without prior notification to the Company. The Company may recalculate the rate or change the rate eligibility in such instances.

2. Should a Customer request relocation of a Dusk to Dawn lighting installation, the costs of such relocation will be paid by the Customer.

3. The Customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of photocontrols or fixtures) within ten (10) working days from notification by Customer. If the maintenance requires cable replacement or repairs, the Company will use reasonable efforts to complete said repairs within twenty (20) working days.

4. The Customer's bill will not be reduced due to photocontrol or cable repair or replacement outages.

5. The Customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

6. Lighting equipment, which is not specified in this rate schedule, will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

7. Lighting Equipment and services with an initial Company cost exceeding $-25,000 will require a financial liability agreement between the Company and the Customer.

8. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill. In addition, service may be subject to special terms and conditions as provided for in a Customer contract or service agreement.

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the Customer requests any non-standard Dusk to Dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the Customer will own, operate, and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Monthly bills rendered for non-standard facilities will consist of the following rates, plus any adjustments incorporated in this schedule. KWh will be determined by the Company, based on the rated wattage of the equipment and an estimated average hourly usage per month.

A.	Service Charge	$ 4.093.54	per installed fixture per month
B.	Energy Charge	$ 0.079490.06857	per kWh per month

CONTRACT PERIOD

All Dusk to Dawn lighting installations will require a written agreement for service for a minimum of ten (10) years from the date of initial delivery of service. It shall continue in effect thereafter, unless terminated by either party on thirty (30) days' written notice.

AVAILABILITY

This rate schedule is applicable to Customers for Dusk to Dawn lighting.

This rate schedule is frozen as of December 1, 2021. This means a Customer that was already taking service under this rate schedule before that date may continue service under this rate schedule, but no Customers connecting service after that date will be eligible to choose to be served under this rate schedule.

DESCRIPTION

The E-47 rate is available to Customers with Dusk to Dawn lights. These lights are on the Customer's property or a private street, and the Customer is charged a monthly fee for the light. This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company.

TIME PERIOD

Dusk: The time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

I. FIXTURES (Includes Mounting Arm, if Applicable)

				CHARGES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
A. Acorn	3,835 LED	75	26	$24.48~~21.19~~	$3.10~~2.68~~
	4,796 LED	75	26	$19.66~~17.02~~	$3.04~~2.63~~
	5,003 LED	100	35	$26.53~~22.97~~	$4.09~~3.54~~
	5,904 LED	100	35	$26.06~~22.56~~	$4.09~~3.54~~
	6,000 IND	85	29	$21.77~~18.85~~	$3.37~~2.92~~
B. Architectural	6,200 IND	85	29	$11.46~~9.92~~	$3.37~~2.92~~
	8,400 IND	100	34	$12.09~~10.47~~	$3.84~~3.32~~
	10,200 IND	120	41	$13.30~~11.51~~	$4.47~~3.87~~
	13,000 IND	150	52	$14.68~~12.71~~	$5.48~~4.74~~

FROZEN

				CHARGES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
B. Architectural (con~~'~~t.)	20,500 IND	200	69	$16.73~~14.48~~	$7.05~~6.10~~
	22,500 IND	265	91	$19.95~~17.27~~	$9.07~~7.85~~
	3,300 LED	43	15	$11.59~~10.03~~	$1.77~~1.53~~
	3,800 LED	32	12	$8.74~~7.57~~	$1.41~~1.22~~
	3,900 LED	32	12	$11.27~~9.76~~	$1.44~~1.25~~
	4,050 LED	63	22	$21.08~~18.25~~	$2.63~~2.28~~
	4,100 LED	45	16	$11.70~~10.13~~	$1.88~~1.63~~
	4,800 LED	41	15	$9.36~~8.10~~	$1.74~~1.51~~
	5,000 LED	41	15	$10.87~~9.41~~	$1.76~~1.52~~
	5,100 LED	60	21	$11.52~~9.97~~	$2.40~~2.08~~
	5,300 LED	67	24	$11.85~~10.26~~	$2.73~~2.36~~
	5,800 LED	94	32	$20.15~~17.44~~	$3.65~~3.16~~
	5,890 LED	89	31	$23.26~~20.14~~	$3.62~~3.13~~
	6,000 LED	62	22	$21.08~~18.25~~	$2.63~~2.28~~
	6,000 LED	67	24	$22.50~~19.48~~	$2.86~~2.48~~
	6,810 LED	101	35	$21.37~~18.50~~	$4.03~~3.49~~
	7,100 LED	62	22	$22.29~~19.30~~	$2.65~~2.29~~
	7,400 LED	127	44	$23.10~~20.00~~	$4.75~~4.11~~
	7,500 LED	73	26	$22.72~~19.67~~	$3.07~~2.66~~
	7,700 LED	86	30	$20.83~~18.03~~	$3.49~~3.02~~
	8,200 LED	88	31	$11.83~~10.24~~	$3.48~~3.01~~
	8,200 LED	95	33	$13.43~~11.63~~	$3.70~~3.20~~
	8,300 LED	72	25	$20.28~~17.56~~	$2.95~~2.55~~
	8,300 LED	106	37	$14.08~~12.19~~	$4.14~~3.58~~
	8,500 LED	88	31	$13.23~~11.45~~	$3.50~~3.03~~
	9,020 LED	139	48	$25.96~~22.47~~	$5.44~~4.71~~
	9,900 LED	130	45	$15.64~~13.54~~	$5.00~~4.33~~
	10,000 LED	93	32	$24.25~~20.99~~	$3.73~~3.23~~
	10,000 LED	113	39	$15.00~~12.99~~	$4.37~~3.78~~
	10,600 LED	126	44	$25.53~~22.10~~	$5.01~~4.34~~
	11,100 LED	108	38	$14.44~~12.50~~	$4.24~~3.67~~
	11,500 LED	108	38	$14.89~~12.89~~	$4.25~~3.68~~
	12,300 LED	203	70	$28.83~~24.96~~	$7.14~~6.18~~
	12,900 LED	119	41	$25.24~~21.85~~	$4.69~~4.06~~
	13,260 LED	202	70	$30.67~~26.55~~	$7.85~~6.80~~
	14,000 LED	171	59	$29.50~~25.54~~	$6.68~~5.78~~
	15,000 LED	136	47	$28.21~~24.42~~	$5.38~~4.66~~
	15,400 LED	144	50	$28.52~~24.69~~	$5.71~~4.94~~
	18,300 LED	162	56	$18.25~~15.80~~	$6.21~~5.38~~
	19,200 LED	257	89	$30.40~~26.32~~	$9.86~~8.54~~
	20,000 LED	258	89	$30.40~~26.32~~	$9.86~~8.54~~
	20,300 LED	193	67	$19.43~~16.82~~	$7.39~~6.40~~

FROM FILE

					CHARGES	
		Lumen	Watts	kWh	Company Owned	Customer Owned
B. Architectural (cont.)		21,000 LED	193	67	$28.02~~24.26~~	$7.49~~6.48~~
C. Cobra		6,200 IND	75	26	$11.92~~10.32~~	$3.10~~2.68~~
		6,400 IND	85	29	$10.15~~8.79~~	$3.37~~2.92~~
		8,000 IND	88	30	$11.85~~10.26~~	$3.47~~3.00~~
		8,400 IND	100	34	$10.97~~9.50~~	$3.84~~3.32~~
		10,200 IND	120	41	$11.82~~10.23~~	$4.47~~3.87~~
		13,000 IND	150	52	$13.01~~11.26~~	$5.48~~4.74~~
		15,250 IND	200	69	$15.69~~13.58~~	$7.05~~6.10~~
		22,500 IND	250	86	$20.99~~18.17~~	$8.59~~7.44~~
	Gray/Bronze	3,500 IND	55	19	$11.87~~10.28~~	$2.45~~2.12~~
		6,000 LED	95	33	$19.29~~16.70~~	$3.74~~3.24~~
		8,700 LED	142	49	$21.69~~18.78~~	$5.21~~4.51~~
		9,600 LED	157	54	$23.08~~19.98~~	$5.67~~4.91~~
		11,600 B-LED	181	62	$21.53~~18.64~~	$6.39~~5.53~~
	Gray/Bronze	3,300 LED	43	15	$10.19~~8.82~~	$2.08~~1.80~~
	Gray/Bronze	5,300 LED	67	23	$11.83~~10.24~~	$2.82~~2.44~~
	Gray/Bronze	8,300 LED	106	37	$15.33~~13.27~~	$4.11~~3.56~~
	Gray/Bronze	10,500 LED	130	45	$17.06~~14.77~~	$4.84~~4.19~~
	Gray/Bronze	20,000 LED	258	89	$29.65~~25.67~~	$8.89~~7.70~~
D. Decorative Transit		5,300 LED	75	26	$32.18~~27.86~~	$3.10~~2.68~~
		8,300 LED	100	34	$34.46~~29.83~~	$3.84~~3.32~~
		8,147 LED	75	26	$40.46~~35.03~~	$3.30~~2.86~~
		9,522 LED	100	35	$40.89~~35.40~~	$4.26~~3.69~~
		10,500 LED	150	52	$36.99~~32.02~~	$5.48~~4.74~~
		14,896 LED	150	52	$45.23~~39.16~~	$6.12~~5.30~~
	Double	8,147 LED	75	26	$73.25~~63.41~~	$3.53~~3.06~~
	Double	9,522 LED	100	35	$73.16~~63.34~~	$4.51~~3.90~~
	Double	14,896 LED	100	52	$79.96~~69.22~~	$6.33~~5.48~~
	Copper	6,000 IND	85	29	$21.35~~18.48~~	$3.37~~2.92~~
	Gray/Black	8,000 IND	88	30	$16.82~~14.56~~	$3.47~~3.00~~
	Gray/Black	4,350 LED	86	30	$15.25~~13.20~~	$3.47~~3.00~~
E. Flood		14,470 LED	148	51	$27.08~~23.44~~	$5.80~~5.02~~
		16,000 LED	125	43	$26.22~~22.70~~	$4.93~~4.27~~
F. Pendant		8,678 LED	75	26	$29.82~~25.82~~	$3.17~~2.74~~
		13,964 LED	100	35	$31.50~~27.27~~	$4.15~~3.59~~
G. Post Top		4,350 LED	86	30	$15.19~~13.15~~	$3.41~~2.95~~
		6,400 LED	30	30	$15.19~~13.15~~	$3.41~~2.95~~
		6,600 LED	83	29	$15.09~~13.06~~	$3.29~~2.85~~
H. Roadway		3,300 LED	43	15	$10.71~~9.27~~	$1.76~~1.52~~
		3,800 LED	32	12	$8.19~~7.09~~	$1.41~~1.22~~
		3,900 LED	32	12	$10.38~~8.99~~	$1.43~~1.24~~
		4,100 LED	45	16	$10.81~~9.36~~	$1.87~~1.62~~

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				CHARGES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
H. Roadway (cont.)	4,800 LED	41	15	$8.787.60	$1.731.50
	5,000 LED	41	15	$10.328.93	$1.761.52
	5,100 LED	60	21	$10.969.49	$2.402.08
	5,300 LED	67	24	$11.309.78	$2.732.36
	8,200 LED	88	31	$11.009.52	$3.473.00
	8,200 LED	95	33	$12.8611.13	$3.693.19
	8,300 LED	106	37	$13.2811.50	$4.123.57
	8,500 LED	88	31	$12.6510.95	$3.493.02
	9,900 LED	130	45	$15.0613.04	$4.994.32
	10,000 LED	113	39	$14.4312.49	$4.353.77
	11,100 LED	108	38	$13.6111.78	$4.243.67
	11,500 LED	108	38	$14.3112.39	$4.243.67
	18,300 LED	162	56	$17.2314.92	$6.195.36
	19,200 LED	257	89	$21.6218.72	$9.758.44
	20,000 LED	258	89	$21.6218.72	$9.758.44
	20,300 LED	193	67	$18.4115.94	$7.376.38
	21,000 LED	193	67	$19.2416.66	$7.386.39
Acorn	4,000 INC	295	103	$11.9210.32	$6.675.77
	7,000 MV	175	73	$8.867.67	$15.4413.37
	20,000 MV	400	150	$30.3726.29	$17.2114.90
	9,500 HPS	100	41	$32.9728.54	$11.249.73
	16,000 HPS	150	69	$36.6131.69	$14.2012.29
Architectural	9,500 HPS	100	41	$18.7416.22	$8.707.53
	16,000 HPS	150	69	$21.8818.94	$11.9710.36
	30,000 HPS	250	99	$25.9722.48	$15.3513.29
	50,000 HPS	400	153	$32.0427.74	$22.1019.13
	14,000 MH	175	72	$26.2222.70	$14.3712.44
	21,000 MH	250	101	$29.7725.77	$17.7215.34
	36,000 MH	400	159	$37.2232.22	$24.3721.10
	8,000 LPS	55	30	$27.2523.59	$11.9710.36
	13,500 LPS	90	50	$32.1227.81	$14.4412.50
	22,500 LPS	135	72	$36.7031.77	$17.6015.24
	33,000 LPS	180	90	$44.1438.21	$20.7317.95
Cobra Roadway	5,800 HPS	70	29	$10.649.21	$6.305.45
	9,500 HPS	100	41	$12.5210.84	$7.706.67
	16,000 HPS	150	69	$15.6913.58	$10.759.31
	30,000 HPS	250	99	$18.9216.38	$13.9812.10
	50,000 HPS	400	153	$25.6722.22	$19.9517.27
	14,000 MH	175	72	$18.2415.79	$12.4310.76
	21,000 MH	250	101	$21.3118.45	$15.4713.39
	36,000 MH	400	159	$28.0724.30	$21.4918.60
	8,000 FL	100	38	$20.9718.15	$6.155.32

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					CHARGES	
		Lumen	Watts	kWh	Company Owned	Customer Owned
Decorative Transit		9,500 HPS	100	41	$45.20~~39.13~~	$13.53~~11.71~~
		16,000 HPS	150	69	$44.95~~38.91~~	$7.69~~6.66~~
		30,000 HPS	250	99	$51.75~~44.80~~	$19.53~~16.91~~
Flood		30,000 HPS	250	99	$25.11~~21.74~~	$15.61~~13.51~~
		50,000 HPS	400	153	$31.15~~26.97~~	$21.66~~18.75~~
		21,000 MH	250	101	$26.80~~23.20~~	$16.50~~14.28~~
		36,000 MH	400	159	$32.69~~28.30~~	$22.35~~19.35~~
Post Top		8,000 FL	100	38	$22.59~~19.56~~	$6.38~~5.52~~
	Colonial	9,500 HPS	100	41	$12.93~~11.19~~	$8.10~~7.01~~
	Colonial	9,500 HPS	100	41	$14.88~~12.88~~	$8.39~~7.26~~
	Decorative	9,500 HPS	100	41	$39.56~~34.25~~	$12.48~~10.80~~
Brackets over 8 ft. and up to 16 ft. in length					$2.09~~1.81~~	—

The following lamps will be available for 90 days following the effective date of revision 57. At that time, these lamps will be frozen consistent with all other elements of the rate schedule.

				CHARGES	
	Lumens	Watts	kWh	Company Owned	Customer Owned
ARCHITECTURAL/RW BRONZE	4,300 LED	45	16	$11.94~~10.34~~	$1.92~~1.66~~
	20,100 LED	174	60	$19.07~~16.51~~	$6.78~~5.87~~
	21,000 LED	174	60	$27.85~~24.11~~	$6.88~~5.96~~
COBRA/GRAY	20,100 LED	174	60	$18.03~~15.61~~	$6.76~~5.85~~
	21,000 LED	174	60	$18.89~~16.35~~	$6.77~~5.86~~
ROADWAY/GRAY	4,300 LED	45	16	$11.31~~9.79~~	$1.91~~1.65~~
	5,400 LED	60	21	$11.19~~9.69~~	$2.45~~2.12~~
	8,600 LED	95	33	$13.12~~11.36~~	$3.77~~3.26~~
POST TOP/SALEM BLACK	6,400 LED	83	29	$14.43~~12.49~~	$3.35~~2.90~~
	4,350 LED	86	30	$14.54~~12.59~~	$3.47~~3.00~~
TOWN AND COUNTRY/GRAY	5,600 LED	56	20	$10.58~~9.16~~	$2.33~~2.02~~
TOWN AND COUNTRY/BLACK	5,600 LED	56	20	$10.58~~9.16~~	$2.33~~2.02~~
DECORATIVE TRANSIT/SINGLE	3,720 LED	37	13	$44.83~~38.81~~	$2.01~~1.74~~

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ROADWAY ARCHITECTURAL -BRONZE	3,408 LED	31	11	$9.688.38	$1.341.16
	4,800 LED	43	15	$10.128.76	$1.781.54
	4,900 LED	43	15	$9.958.61	$1.781.54
	7,810 LED	68	24	$12.9511.21	$2.802.42
	8,165 LED	68	24	$12.9411.2	$2.802.42
	11,000 LED	96	34	$14.0812.19	$3.893.37
	11,500 LED	98	34	$14.0312.15	$3.893.37
COBRA ROADWAY/GRAY	3,408 LED	31	11	$8.957.75	$1.331.15
	4,800 LED	43	15	$9.398.13	$1.771.53
	4,900 LED	43	15	$9.458.18	$1.771.53
	7,810 LED	68	24	$12.0210.41	$2.782.41
	8,165 LED	68	24	$12.2410.6	$2.782.41
	11,000 LED	96	34	$13.1611.39	$3.883.36
	11,500 LED	96	34	$13.0411.29	$3.883.36
FLOOD	14,500 LED	96	34	$16.9914.71	$3.933.40

NOTES:

1. Company Owned fixtures are those fixtures that the Company installs, owns, and operates.

2. Customer Owned fixtures are those fixtures where the Customer owns and maintains the lighting fixtures, and the Company approves the installation, operates the fixtures, and replaces Company standard lamps only. The Company may replace standard lamps if it has a maintenance agreement with the customer.

3. Listed kWh reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

4. HPS = High Pressure Sodium

5. MH = Metal Halide

6. LPS = Low Pressure Sodium

7. FL = Fluorescent

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8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those Customers being served and those installations in service on April 21, 1983.

9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those Customers being served and those installation in service on June 1, 1987 in accordance with A.R.S. §49-1104(A).

10. LED = Light Emitting Diode

11. IND = Induction

13. B-LED = Beta Light Emitting Diode

II. POLES

				CHARGES
			Height	Company Owned
A. Anchor Base Mounted	Round Steel	1 Simplex Adapter	12 ft.	$14.83~~12.84~~
			22 ft.	$16.69~~14.45~~
			25 ft.	$18.07~~15.64~~
			30 ft.	$20.75~~17.96~~
			32 ft.	$21.80~~18.87~~
	Round Steel	2 Simplex Adapters	12 ft.	$15.81~~13.69~~
			22 ft.	$18.17~~15.73~~
			25 ft.	$18.96~~16.41~~
			30 ft.	$22.03~~19.07~~
			32 ft.	$23.49~~20.34~~
	Square Steel	5"	13 ft.	$17.00~~14.72~~
			15 ft.	$15.19~~13.15~~
			23 ft.	$18.02~~15.60~~
			25 ft.	$19.81~~17.15~~
			28 ft.	$21.99~~19.04~~
			32 ft.	$21.87~~18.93~~
	Concrete		12 ft.	$50.67~~43.87~~
	Fiberglass		12 ft.	$42.91~~37.15~~
	Decorative Transit	4"	16 ft.	$41.84~~36.22~~
	Decorative Transit	6"	30 ft.	$80.78~~69.93~~
	Hinged	Square	15 ft.	$16.08~~13.92~~
		Round	19 ft.	$14.54~~12.59~~
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$14.27~~12.35~~
			22 ft.	$16.14~~13.97~~
			25 ft.	$17.49~~15.14~~

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				CHARGES
			Height	Company Owned
B. Anchor Base Mounted			30 ft.	$20.19~~17.48~~
			32 ft.	$21.22~~18.37~~
	Round Steel	2 Simplex Adapters	12 ft.	$15.24~~13.19~~
			22 ft.	$17.03~~14.74~~
			25 ft.	$18.38~~15.91~~
			30 ft.	$21.46~~18.58~~
			32 ft.	$22.92~~19.84~~
		3 Bolt Arm	32 ft.	$26.34~~22.80~~
	Square Steel	5"	13 ft.	$16.45~~14.24~~
			15 ft.	$16.82~~14.56~~
			23 ft.	$17.45~~15.11~~
			25 ft.	$19.26~~16.67~~
			28 ft.	$21.39~~18.52~~
			32 ft.	$22.21~~19.23~~
C. Direct Bury	Round Steel		19 ft.	$22.44~~19.43~~
			30 ft.	$17.52~~15.17~~
			38 ft.	$21.38~~18.51~~
		Self-Support	40 ft.	$26.34~~22.80~~
		Stepped	25 ft.	$60.59~~52.45~~
			32 ft.	$63.81~~55.24~~
			49 ft.	$79.21~~68.57~~
	Square Steel	4"	34 ft.	$19.34~~16.74~~
		5"	20 ft.	$18.37~~15.90~~
			30 ft.	$19.14~~16.57~~
			38 ft.	$20.77~~17.98~~
		8"	28 ft.	$34.66~~30.01~~
			32 ft.	$36.24~~31.37~~
	Decorative Transit		41 ft. 6 in.	$24.95~~21.60~~
	Decorative Transit		47 ft.	$31.08~~26.91~~
	Steel Distribution Pole (for lighting)		35 ft.	$28.69~~24.84~~
D. Post Top	Decorative Transit Anchor		16 ft.	$42.74~~37.00~~
	Gray Steel/Fiberglass		23 ft.	$14.82~~12.83~~
	Black Steel		23 ft.	$16.33~~14.14~~
	Wood Poles		30 ft.	$10.90~~9.44~~
			35 ft.	$10.90~~9.44~~
			40 ft.	$15.52~~13.44~~

NOTES: 1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.

2. Monthly charges for all new Company Owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary

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line if Customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in Section IV.1 below.

3. When adding lighting fixtures to an existing Company Owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified in Section IV.1 below.

4. Any and all distribution wire required to serve lighting facilities placed on a Customer Owned pole, whether new or existing, is subject to the additional monthly wire charges specified in Section IV.1 below.

III. ANCHOR BASE

		CHARGES
	Height	Company Owned
A. Flush	4 ft.	$12.07~~10.45~~
	6 ft.	$14.40~~12.47~~
B. Pedestal	8 ft.	$16.51~~14.29~~
For 32' Round Steel Pole only	4 ft. 6"	$11.45~~9.91~~

IV. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	CHARGE
	Company Owned
1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire, if Customer provides earthwork and conduit.	$4.26~~3.69~~
2. Additional maintenance charge for HPS lamp and luminaire that is not accessible by bucket truck.	$3.41~~2.95~~
3. Additional maintenance charge for MH lamp and luminaire that is not accessible by bucket truck.	$7.37~~6.38~~

V. DETERMINATION OF CHARGES FOR NEW EQUIPMENT

Monthly charges for new lighting fixtures, poles and other equipment not included in Sections I, II, or III above will be determined by the Company using the following method:

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Step 1 Determination of monthly charges for each charge type

Charge Type	Monthly Charge		Cost Inputs		PV Factor		Monthly Fixed Charge Rate
1	Carrying cost (fixtures)	=	Equipment cost (installed)	x	NA	x	1.518%
2	Lighting O&M	=	O&M cost (lifecycle)	x	0.427	x	1.518%
3	Carrying cost (poles)	=	Equipment cost (installed)	x	NA	x	1.296%

Charge Type	Monthly Charge		kWh Input		$/kWh
4	Generation	=	kWh per month	x	0.07676~~0.06621~~
5	T&D, RCS, system benefits	=	kWh per month	x	0.03126~~0.02682~~

Step 2 Determination of Total Monthly Charge
The total monthly charge will be the summation of the charges for each applicable charge type.

Equipment	Charge Type
Fixtures - Company Owned	1,2,4,5
Fixtures - Customer Owned	2,4,5
Poles - Company Owned	3

TRIP CHARGE

A $100.00 trip charge per light will be charged when a Customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their dusk to dawn equipment.

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ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM

~~7.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. The 4,000 and 7,000 lumen lamps use an open glass diffuser. All units are controlled by a photoelectric switch.

2. The Customer is not authorized to make connections to the lighting circuits or to make attachments without prior notification to the Company. The Company may recalculate the rate or change the rate eligibility in such instances.

3. Should a Customer request relocation of a Dusk to Dawn lighting installation, the costs of such relocation will be paid by the Customer.

4. The Customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by Customer. If the maintenance requires cable replacement or repairs, the Company will use reasonable efforts to complete said repairs within twenty (20) working days.

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5. The Customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

6. The Customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment, multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

7. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

8. Lighting Equipment and services with an initial Company cost exceeding $25,000 will require a financial liability agreement between the Company and the Customer.

9. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the Customer requests any non-standard Dusk to Dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the Customer will own, operate and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Monthly bills rendered for non-standard facilities will consist of the following rates, plus any adjustments incorporated in this schedule. KWh will be determined by the Company, based on the rated wattage of the equipment and an estimated average hourly usage per month.

A.	Service Charge	$ 4.093.54	per installed fixture per month
B.	Energy Charge	$ 0.079490.06857	per kWh per month

CONTRACT PERIOD

All Dusk to Dawn lighting installations will require a written agreement for service for a minimum of ten (10) years, or longer at Company's option.

PROPOSED

AVAILABILITY

This rate schedule is applicable to those portions of cities, towns and unincorporated communities in which the Company does a general retail electric business and where the Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

This rate schedule is frozen as of December 1, 2021. This means a Customer that was already taking service under this rate schedule before that date may continue service under this rate schedule, but no Customers connecting service after that date will be eligible to be served under this rate schedule.

DESCRIPTION

E-58 is a rate that is applicable for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of Company's facilities.

TIME PERIODS

Dusk: Time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

CHARGES

The monthly bill will consist of the following charges, plus adjustments.

I. FIXTURES (Includes Mounting Arm, if Applicable)

				CHARGES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
A. Acorn	3,835 LED	75	26	$25.12~~21.19~~	$8.80~~7.43~~
	4,796 LED	75	26	$20.17~~17.02~~	$7.49~~6.33~~
	5,003 LED	100	35	$27.23~~22.97~~	$10.10~~8.53~~
	5,904 LED	100	35	$26.75~~22.56~~	$9.97~~8.42~~
	6000 IND	85	29	$22.34~~18.85~~	$5.95~~5.03~~
B. Architectural	6,200 IND	85	29	$11.75~~9.92~~	$4.55~~3.85~~
	8,400 IND	100	34	$12.40~~10.47~~	$5.05~~4.27~~
	10,200 IND	120	41	$13.64~~11.51~~	$5.78~~4.89~~
	13,000 IND	150	52	$15.06~~12.71~~	$6.87~~5.81~~
	20,500 IND	200	69	$17.16~~14.48~~	$8.55~~7.22~~

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	Lumen	Watts	kWh	CHARGES Investment by Company	CHARGES Investment by Others
B. Architectural (cont.)	22,500 IND	265	91	$20.47~~17.27~~	$10.76~~9.09~~
	3,300 LED	43	15	$11.88~~10.03~~	$4.38~~3.71~~
	3,800 LED	32	12	$8.96~~7.57~~	$3.37~~2.86~~
	3,900 LED	32	12	$11.56~~9.76~~	$4.06~~3.44~~
	4,050 LED	63	22	$21.63~~18.25~~	$7.56~~6.39~~
	4,100 LED	45	16	$12.00~~10.13~~	$4.50~~3.81~~
	4,800 LED	41	15	$9.59~~8.10~~	$3.78~~3.20~~
	5,000 LED	41	15	$11.14~~9.41~~	$4.19~~3.55~~
	5,100 LED	60	21	$11.81~~9.97~~	$4.84~~4.10~~
	5,300 LED	67	24	$12.15~~10.26~~	$5.19~~4.39~~
	5,800 LED	94	32	$20.67~~17.44~~	$5.97~~5.05~~
	5,890 LED	89	31	$23.88~~20.14~~	$8.88~~7.50~~
	6,000 LED	62	22	$21.63~~18.25~~	$7.56~~6.39~~
	6,000 LED	67	24	$23.09~~19.48~~	$8.11~~6.85~~
	6,400 LED	89	31	$20.77~~17.52~~	$5.91~~5.00~~
	6,810 LED	101	35	$21.93~~18.50~~	$8.70~~7.35~~
	7,100 LED	62	22	$22.88~~19.30~~	$7.88~~6.66~~
	7,400 LED	127	44	$23.71~~20.00~~	$7.35~~6.21~~
	7,500 LED	73	26	$23.32~~19.67~~	$8.32~~7.03~~
	7,700 LED	86	30	$21.37~~18.03~~	$8.14~~6.88~~
	8,200 LED	88	31	$12.13~~10.24~~	$5.76~~4.87~~
	8,200 LED	95	33	$13.78~~11.63~~	$6.35~~5.37~~
	8,300 LED	72	25	$20.81~~17.56~~	$7.59~~6.41~~
	8,300 LED	106	37	$14.44~~12.19~~	$6.85~~5.79~~
	8,500 LED	88	31	$13.56~~11.45~~	$6.14~~5.19~~
	9,020 LED	139	48	$26.64~~22.47~~	$10.99~~9.28~~
	9,200 LED	139	48	$29.74~~25.08~~	$8.46~~7.15~~
	9,900 LED	130	45	$16.04~~13.54~~	$7.93~~6.70~~
	10,000 LED	93	32	$24.88~~20.99~~	$9.23~~7.80~~
	10,000 LED	113	39	$15.39~~12.99~~	$7.28~~6.15~~
	10,600 LED	126	44	$26.20~~22.10~~	$10.54~~8.90~~
	11,100 LED	108	38	$14.81~~12.50~~	$7.04~~5.95~~
	11,500 LED	108	38	$15.27~~12.89~~	$7.16~~6.05~~
	12,300 LED	203	70	$29.59~~24.96~~	$10.27~~8.67~~
	12,900 LED	119	41	$25.90~~21.85~~	$10.23~~8.64~~
	13,260 LED	202	70	$31.48~~26.55~~	$14.06~~11.87~~
	13,620 LED	202	70	$33.09~~27.91~~	$10.72~~9.05~~
	14,000 LED	171	59	$30.28~~25.54~~	$12.85~~10.85~~
	15,000 LED	136	47	$28.95~~24.42~~	$11.54~~9.74~~
	15,400 LED	144	50	$29.27~~24.69~~	$11.86~~10.01~~
	18,300 LED	162	56	$18.73~~15.80~~	$9.53~~8.05~~
	19,200 LED	257	89	$31.21~~26.32~~	$15.53~~13.11~~
	20,000 LED	258	89	$31.21~~26.32~~	$15.53~~13.11~~

FROZEN

					CHARGES	
		Lumen	Watts	kWh	Investment by Company	Investment by Others
B. Architectural (cont.)		20,300 LED	193	67	$19.94~~16.82~~	$10.74~~9.07~~
		21,000 LED	193	67	$28.76~~24.26~~	$13.09~~11.05~~
C. Cobra		6,200 IND	75	26	$12.22~~10.32~~	$4.36~~3.69~~
		6,400 IND	85	29	$10.41~~8.79~~	$4.37~~3.70~~
		8,000 IND	88	30	$12.15~~10.26~~	$4.68~~3.96~~
		8,400 IND	100	34	$11.25~~9.50~~	$4.90~~4.15~~
		10,200 IND	120	41	$12.12~~10.23~~	$5.57~~4.71~~
		13,000 IND	150	52	$13.34~~11.26~~	$6.64~~5.61~~
		15,250 IND	200	69	$16.09~~13.58~~	$8.40~~7.10~~
		22,500 IND	250	86	$21.54~~18.17~~	$10.50~~8.87~~
	Gray/Bronze	3,500 IND	55	19	$12.18~~10.28~~	$3.78~~3.20~~
		6,000 LED	95	33	$19.79~~16.70~~	$5.94~~5.02~~
		8,700 LED	142	49	$22.26~~18.78~~	$7.57~~6.40~~
		9,600 LED	157	54	$23.69~~19.98~~	$8.17~~6.90~~
		11,600 B-LED	181	62	$22.10~~18.64~~	$8.63~~7.29~~
	Gray/Bronze	3,300 LED	43	15	$10.44~~8.82~~	$3.22~~2.73~~
	Gray/Bronze	5,300 LED	67	23	$12.13~~10.24~~	$4.10~~3.47~~
	Gray/Bronze	8,300 LED	106	37	$15.72~~13.27~~	$5.72~~4.84~~
	Gray/Bronze	10,500 LED	130	45	$17.50~~14.77~~	$6.59~~5.57~~
	Gray/Bronze	20,000 LED	258	89	$30.44~~25.67~~	$11.92~~10.06~~
D. Decorative Transit		5,300 LED	75	26	$33.03~~27.86~~	$7.09~~5.99~~
		8,300 LED	100	34	$35.37~~29.83~~	$8.08~~6.83~~
		8,147 LED	75	26	$41.54~~35.03~~	$13.19~~11.13~~
		9,522 LED	100	35	$41.98~~35.40~~	$14.03~~11.84~~
		10,500 LED	150	52	$37.97~~32.02~~	$9.89~~8.35~~
		14,896 LED	150	52	$46.44~~39.16~~	$16.59~~14.00~~
	Double	8,147 LED	75	26	$75.21~~63.41~~	$22.01~~18.57~~
	Double	9,522 LED	100	35	$75.13~~63.34~~	$22.74~~19.18~~
	Double	14,896 LED	100	52	$82.11~~69.22~~	$25.92~~21.86~~
	Copper	6,000 IND	85	29	$21.91~~18.48~~	$5.90~~4.99~~
	Gray/Black	8,000 IND	88	30	$17.25~~14.56~~	$5.35~~4.53~~
	Gray/Black	4,350 LED	86	30	$15.64~~13.20~~	$5.14~~4.35~~
E. Flood		14,470 LED	148	51	$27.79~~23.44~~	$11.55~~9.75~~
		16,000 LED	125	43	$26.91~~22.70~~	$10.66~~9.00~~
F. Pendant		8,678 LED	75	26	$30.61~~25.82~~	$10.27~~8.67~~
		13,964 LED	100	35	$32.33~~27.27~~	$11.46~~9.68~~
G. Post Top		4,350 LED	86	30	$15.58~~13.15~~	$6.59~~5.57~~
		6,400 LED	30	30	$15.58~~13.15~~	$6.59~~5.57~~
		6,600 LED	83	29	$15.48~~13.06~~	$6.48~~5.48~~
H. Roadway		3,300 LED	43	15	$10.98~~9.27~~	$4.14~~3.51~~
		3,800 LED	32	12	$8.39~~7.09~~	$3.22~~2.73~~
		3,900 LED	32	12	$10.65~~8.99~~	$3.81~~3.23~~

FERC

				CHARGES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
H. Roadway (cont.)	4,100 LED	45	16	$11.09~~9.36~~	$4.25~~3.60~~
	4,800 LED	41	15	$9.00~~7.60~~	$3.62~~3.07~~
	5,000 LED	41	15	$10.58~~8.93~~	$4.04~~3.42~~
	5,100 LED	60	21	$11.24~~9.49~~	$4.70~~3.98~~
	5,300 LED	67	24	$11.58~~9.78~~	$5.03~~4.26~~
	8,200 LED	88	31	$11.28~~9.52~~	$5.52~~4.67~~
	8,200 LED	95	33	$13.19~~11.13~~	$6.19~~5.23~~
	8,300 LED	106	37	$13.62~~11.50~~	$6.62~~5.60~~
	8,500 LED	88	31	$12.97~~10.95~~	$5.97~~5.05~~
	9,900 LED	130	45	$15.45~~13.04~~	$7.76~~6.56~~
	10,000 LED	113	39	$14.80~~12.49~~	$7.11~~6.01~~
	11,100 LED	108	38	$13.96~~11.78~~	$6.81~~5.76~~
	11,500 LED	108	38	$14.68~~12.39~~	$7.00~~5.92~~
	18,300 LED	162	56	$17.68~~14.92~~	$9.26~~7.82~~
	19,200 LED	257	89	$22.19~~18.72~~	$13.14~~11.09~~
	20,000 LED	258	89	$22.19~~18.72~~	$13.14~~11.09~~
	20,300 LED	193	67	$18.89~~15.94~~	$10.47~~8.84~~
	21,000 LED	193	67	$19.75~~16.66~~	$10.69~~9.03~~
Acorn	4,000 INC	295	103	$12.22~~10.32~~	$6.83~~5.77~~
	7,000 MV	175	73	$15.84~~13.37~~	$9.08~~7.67~~
	11,000 MV	250	96	$19.84~~16.74~~	$12.11~~10.22~~
	20,000 MV	400	150	$31.17~~26.29~~	$17.66~~14.90~~
	9,500 HPS	100	41	$33.84~~28.54~~	$11.52~~9.73~~
	16,000 HPS	150	69	$37.58~~31.69~~	$14.56~~12.29~~
Architectural	9,500 HPS	100	41	$19.22~~16.22~~	$9.16~~7.74~~
	16,000 HPS	150	69	$22.95~~19.36~~	$22.45~~18.94~~
	30,000 HPS	250	99	$26.65~~22.48~~	$15.75~~13.29~~
	50,000 HPS	400	153	$32.89~~27.74~~	$22.68~~19.13~~
	14,000 MH	175	72	$26.91~~22.70~~	$14.74~~12.44~~
	21,000 MH	250	101	$30.56~~25.77~~	$18.18~~15.34~~
	36,000 MH	400	159	$38.21~~32.22~~	$25.01~~21.10~~
	8,000 LPS	55	30	$27.97~~23.59~~	$12.27~~10.36~~
	13,500 LPS	90	50	$32.98~~27.81~~	$14.81~~12.50~~
	22,500 LPS	135	72	$37.67~~31.77~~	$18.06~~15.24~~
	33,000 LPS	180	90	$45.31~~38.21~~	$21.28~~17.95~~
Cobra	5,800 HPS	70	29	$10.91~~9.21~~	$6.45~~5.45~~
	9,500 HPS	100	41	$12.84~~10.84~~	$7.89~~6.67~~
Roadway	16,000 HPS	150	69	$16.09~~13.58~~	$11.03~~9.31~~
	30,000 HPS	250	99	$19.41~~16.38~~	$14.34~~12.10~~

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					CHARGES	
		Lumen	Watts	kWh	Investment by Company	Investment by Others
Cobra Roadway		50,000 HPS	400	153	$26.34~~22.22~~	$20.47~~17.27~~
		14,000 MH	175	72	$18.71~~15.79~~	$12.75~~10.76~~
		21,000 MH	250	101	$21.87~~18.45~~	$15.87~~13.39~~
		36,000 MH	400	159	$28.81~~24.30~~	$22.05~~18.60~~
		8,000 FL	100	38	$21.51~~18.15~~	$6.29~~5.32~~
Decorative Transit		9,500 HPS	100	41	$46.41~~39.13~~	$13.87~~11.71~~
		16,000 HPS	150	69	$46.15~~38.91~~	$15.51~~13.09~~
		30,000 HPS	250	99	$53.13~~44.80~~	$20.04~~16.91~~
Flood		30,000 HPS	250	99	$25.77~~21.74~~	$16.01~~13.51~~
		50,000 HPS	400	153	$31.98~~26.97~~	$22.23~~18.75~~
		21,000 MH	250	101	$27.51~~23.20~~	$16.92~~14.28~~
		36,000 MH	400	159	$33.56~~28.30~~	$22.94~~19.35~~
Post Top	Colonial Gray	8,000 FL	100	38	$23.19~~19.56~~	$6.53~~5.52~~
	Colonial Gray	9,500 HPS	100	41	$13.26~~11.19~~	$8.30~~7.01~~
	Colonial Black	9,500 HPS	100	41	$15.26~~12.88~~	$8.59~~7.26~~
	Decorative	9,500 HPS	100	41	$40.62~~34.25~~	$12.79~~10.80~~

The following lamps will be available for 90 days following the effective date of revision 55. At that time these lamps will be frozen consistent with all other elements of this schedule.

				CHARGES	
	Lumens	Watts	kWh	Investment by Company	Investment by Others
ARCHITECTURAL/RW BRONZE	4,300 LED	45	16	$12.25 ~~10.34~~	$ 4.60 ~~3.89~~
	20,100 LED	174	60	$19.57 ~~16.51~~	$ 10.18 ~~8.60~~
	21,000 LED	174	60	$28.59 ~~24.11~~	$ 12.58 ~~10.62~~
COBRA/GRAY	20,100 LED	174	60	$18.50 ~~15.61~~	$ 9.90 ~~8.36~~
	21,000 LED	174	60	$19.38 ~~16.35~~	$ 10.14 ~~8.56~~
ROADWAY/GRAY	4,300 LED	45	16	$11.60 ~~9.79~~	$ 4.42 ~~3.74~~
	5,400 LED	60	21	$11.48 ~~9.69~~	$ 4.80 ~~4.06~~
ROADWAY	8,600 LED	95	33	$13.46 ~~11.36~~	$ 6.32 ~~5.34~~
POST TOP/SALEM BLACK	6,400 LED	83	29	$14.80 ~~12.49~~	$ 6.34 ~~5.36~~
	4,350 LED	86	30	$14.92 ~~12.59~~	$ 6.46 ~~5.46~~

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TOWN AND COUNTRY/GRAY	5,600 LED	56	20	$10.85 ~~9.16~~	$ 4.56 ~~3.86~~
TOWN AND COUNTRY/BLACK	5,600 LED	56	20	$10.85 ~~9.16~~	$ 4.56 ~~3.86~~
DECORATIVE TRANSIT/SINGLE	3,720 LED	37	13	$46.03 ~~38.81~~	$ 13.35 ~~11.27~~
ROADWAY ARCHITECTURAL -BRONZE	3,408 LED	31	11	$9.92 ~~8.38~~	$ 3.56 ~~3.02~~
	4,800 LED	43	15	$10.37 ~~8.76~~	$ 4.01 ~~3.40~~
	4,900 LED	43	15	$10.20 ~~8.61~~	$ 3.97 ~~3.36~~
	7,810 LED	68	24	$13.28 ~~11.21~~	$ 5.53 ~~4.68~~
	8,165 LED	68	24	$13.27 ~~11.20~~	$ 5.53 ~~4.68~~
	11,000 LED	96	34	$14.44 ~~12.19~~	$ 6.67 ~~5.64~~
	11,500 LED	98	34	$14.40 ~~12.15~~	$ 6.66 ~~5.63~~
COBRA ROADWAY/GRAY	3,408 LED	31	11	$9.18 ~~7.75~~	$ 3.36 ~~2.85~~
	4,800 LED	43	15	$9.63 ~~8.13~~	$ 3.81 ~~3.23~~
	4,900 LED	43	15	$9.69 ~~8.18~~	$ 3.82 ~~3.24~~
	7,810 LED	68	24	$12.33 ~~10.41~~	$ 5.28 ~~4.47~~
	8,165 LED	68	24	$12.56 ~~10.60~~	$ 5.33 ~~4.51~~
	11,000 LED	96	34	$13.49 ~~11.39~~	$ 6.41 ~~5.42~~
	11,500 LED	96	34	$13.38 ~~11.29~~	$ 6.39 ~~5.40~~
FLOOD	14,500 LED	96	34	$17.43 ~~14.71~~	$ 7.47 ~~6.31~~

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.

2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the Customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.

3. Listed kWh~~s~~ reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

4. HPS = High Pressure Sodium

PROPOSED

5. MH = Metal Halide

6. LPS = Low Pressure Sodium

7. FL = Fluorescent

8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those Customers being served and those installations in service on November 1, 1986.

9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those Customers being served and those installation in service on November 1, 1986 in accordance with A.R.S. §49-1104(A).

10. LED = Light Emitting Diode

11. IND = Induction

II. POLES

				CHARGES	
			Height	Investment by Company	Investment by Others
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$15.21~~12.84~~	$2.08~~1.77~~
			22 ft.	$17.12~~14.45~~	$2.34~~1.99~~
			25 ft.	$18.54~~15.64~~	$2.54~~2.16~~
			30 ft.	$21.29~~17.96~~	$2.91~~2.47~~
			32 ft.	$22.37~~18.87~~	$2.95~~2.50~~
		2 Simplex Adapters	12 ft.	$16.22~~13.69~~	$2.22~~1.89~~
			22 ft.	$18.64~~15.73~~	$2.55~~2.17~~
			25 ft.	$19.45~~16.41~~	$2.66~~2.26~~
			30 ft.	$22.61~~19.07~~	$3.10~~2.63~~
			32 ft.	$24.11~~20.34~~	$3.31~~2.81~~
	Square Steel	5"	13 ft.	$17.44~~14.72~~	$2.38~~2.02~~
			15 ft.	$15.58~~13.15~~	$2.13~~1.81~~
			23 ft.	$18.49~~15.60~~	$2.53~~2.15~~
			25 ft.	$20.33~~17.15~~	$2.78~~2.36~~
			28 ft.	$22.57~~19.04~~	$3.09~~2.62~~
			32 ft.	$22.44~~18.93~~	$3.08~~2.61~~
	Concrete		12 ft.	$52.03~~43.87~~	$7.15~~6.04~~
	Fiberglass		12 ft.	$44.06~~37.15~~	$6.04~~5.11~~
	Decorative Transit	4"	16 ft.	$42.95~~36.22~~	$5.91~~5.00~~
	Decorative Transit	6"	30 ft.	$82.95~~69.93~~	$11.41~~9.63~~
	Hinged Poles	Square	15 ft.	$16.50~~13.92~~	$1.33~~1.14~~
		Round	19 ft.	$14.92~~12.59~~	$1.20~~1.03~~

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				CHARGES	
			Height	Investment by Company	Investment by Others
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$14.63~~12.35~~	$1.99~~1.69~~
			22 ft.	$16.55~~13.97~~	$2.26~~1.92~~
			25 ft.	$17.94~~15.14~~	$2.46~~2.09~~
			30 ft.	$20.72~~17.48~~	$2.85~~2.42~~
			32 ft.	$21.78~~18.37~~	$2.98~~2.53~~
		2 Simplex Adapters	12 ft.	$15.63~~13.19~~	$2.13~~1.81~~
			22 ft.	$17.47~~14.74~~	$2.38~~2.02~~
			25 ft.	$18.86~~15.91~~	$2.57~~2.18~~
			30 ft.	$22.02~~18.58~~	$3.01~~2.55~~
			32 ft.	$23.52~~19.84~~	$3.22~~2.73~~
		3 Bolt	32 ft.	$27.03~~22.80~~	$3.69~~3.13~~
	Square Steel	5"	13 ft.	$16.88~~14.24~~	$2.32~~1.97~~
			15 ft.	$17.25~~14.56~~	$2.34~~1.99~~
			23 ft.	$17.91~~15.11~~	$2.46~~2.09~~
			25 ft.	$19.76~~16.67~~	$2.72~~2.31~~
			28 ft.	$21.95~~18.52~~	$3.01~~2.55~~
			32 ft.	$22.80~~19.23~~	$3.10~~2.63~~
C. Direct Bury	Round Steel		19 ft.	$23.03~~19.43~~	$3.16~~2.68~~
			30 ft.	$17.98~~15.17~~	$3.31~~2.81~~
			38 ft.	$21.94~~18.51~~	$3.40~~2.88~~
		Self	40 ft.	$27.03~~22.80~~	$4.26~~3.61~~
		Stepped	25 ft.	$62.21~~52.45~~	$5.06~~4.28~~
			32 ft.	$65.52~~55.24~~	$5.33~~4.51~~
			49 ft.	$81.34~~68.57~~	$11.19~~9.45~~
	Square Steel	4"	34 ft.	$19.84~~16.74~~	$3.42~~2.90~~
		5"	20 ft.	$18.84~~15.90~~	$3.10~~2.63~~
			30 ft.	$19.64~~16.57~~	$3.22~~2.73~~
			38 ft.	$21.31~~17.98~~	$3.68~~3.12~~
		8"	28 ft.	$35.59~~30.01~~	$2.87~~2.44~~
			32 ft.	$37.20~~31.37~~	$3.03~~2.57~~
	Decorative Transit		41 ft 6	$25.61~~21.60~~	$3.74~~3.17~~
	Decorative Transit		47 ft.	$31.91~~26.91~~	$4.68~~3.96~~
	Steel Distribution Pole (for lighting only)		35 ft.	$29.45~~24.84~~	$3.86~~3.27~~
D. Post Top	Decorative Transit Anchor Base		16 ft.	$43.88~~37.00~~	$6.01~~5.08~~
	Gray Steel/Fiberglass		23 ft.	$15.20~~12.83~~	$2.48~~2.11~~
	Black Steel		23 ft.	$16.76~~14.14~~	$2.74~~2.33~~
E. Existing distribution pole suitable for streetlight use				$1.83~~1.56~~	
F. FROZEN	Wood Poles		30 ft.	$11.20~~9.44~~	$1.95~~1.64~~
			35 ft.	$11.20~~9.44~~	$1.85~~1.56~~

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NOTE: The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the Customer provides earthwork and conduit (excluding the underground to overhead transition).

III. ANCHOR BASE

	Height	CHARGES	
		Investment by Company	Investment by Others
A. Flush	4 ft.	$12.38~~10.45~~	$1.69~~1.44~~
	6 ft.	$14.78~~12.47~~	$2.54~~2.16~~
B. Pedestal	8 ft.	$16.93~~14.29~~	$2.93~~2.49~~
For 32' Round Steel Pole only	4 ft. 6"	$11.74~~9.91~~	$2.01~~1.71~~

IV. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	CHARGE
	Company Owned
Underground Circuit Charges:	
a. Per foot of cable, installed under paving	$0.19757~~0~~ ~~.16652~~
b. Per foot of cable, not installed under paving	$0.06973~~0~~ ~~.05877~~

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V. DETERMINATION OF CHARGES FOR NEW EQUIPMENT

Monthly charges for new lighting fixtures, poles and other equipment not included in Sections I, II, or III above will be determined by the Company using the following method:

Step 1 Determination of Charges for each Charge Type

Charge Type	Monthly Charge		Cost Inputs		PV Factor		Monthly Fixed Charge Rate
1	Carrying Cost (fixtures)	=	Equipment Cost (installed)	x	NA	x	1.518%
2	Carrying Cost (poles)	=	Equipment Cost (installed)	x	NA	x	1.296%
3	Fixture Replacement Cost	=	Equipment Cost (installed)	x	0.257	x	1.518%
4	Pole, Anchor Replacement Cost	=	Equipment Cost (installed)	x	0.110	x	1.296%
5	Lighting O&M	=	O&M Cost (lifecycle)	x	0.427	x	1.518%

Charge Type	Monthly Charge		kWh Input		$/kWh
6	Generation	=	kWh per month	x	$0.07856 ~~0.06621~~
7	T&D, RCS, SB	=	kWh per month	x	$0.03182 ~~0.02682~~

Step 2 Determination of Total Monthly Charge

The total monthly charge will be the summation of the charges for each applicable charge type

Equipment	Charge Type
Fixture - IBC	1,5,6,7
Fixture - IBO	3,5,6,7
Pole, Anchor Base - IBC	2
Pole, Anchor Base - IBO	4

FROZEN

TRIP CHARGE

A $100.00 trip charge per light will be charged when a Customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street lighting equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.
2. The Customer will be responsible for notifying the Company when the streetlighting facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by Customer. If the maintenance requires cable replacement or repairs, the Company will use reasonable efforts to complete said repairs within twenty (20) working days.

PROXY

3. The Customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

4. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

5. Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

6. The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the Customer. When the extension is underground the customer will provide earthwork as specified in the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

7. Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

8. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

PROPOSED

RATE SCHEDULE E-59
CLASSIFIED SERVICE
GOVERNMENT OWNED STREET LIGHTING SYSTEMS

AVAILABILITY

This rate schedule is available for government owned outdoor lighting.

DESCRIPTION

This rate schedule is applicable for continuous lighting or dusk to dawn lighting of government owned street lighting systems.

The Customer will own, operate, and maintain the street lighting system including lamps and glass replacements but excluding distribution facilities installed by the Company to serve the lighting system.

TIME PERIOD

Dusk:	The time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights.
Dawn:	The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off the lights.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Basic Service Charge	$3.4802.940	per installed lamp
Energy Charge	$0.076130.06429	per kWh

TRIP CHARGE

A $100.00 trip charge per light will be charged when a Customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street lighting equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~7.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. Billed energy is based upon the summation of the contracted energy rating of installed facilities specified in the street lighting contract.

2. The Customer's bill will not be reduced due to lamp, photocontrol, cable repair or cable replacement outages.

3. At the request of the Customer, Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost. When the extension is underground, the customer will provide earthwork as specified in the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

   a. Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

4. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

5. In addition, service may be subject to special terms and conditions as provided for in a Customer contract or service agreement.

CONTRACT PERIOD

The contract period for service under this rate schedule will be a fixed period of not less than 1 year and not more than 20 years, as agreed to by the Customer and as specified in the street lighting contract.

AVAILABILITY

This rate schedule is available to eligible City of Phoenix service accounts.

DESCRIPTION

E-67 is a rate that is applicable for the lighting of alleys, buildings, and other public places owned or maintained by the City. Street lighting service is not eligible for this schedule. Service to traffic signals is limited to those installations being served as of January 31, 1985, under the Agreement of April 4, 1930, as modified, between Central Arizona Light and Power Company and the City of Phoenix. No new or reconnected traffic signal installations may be served after that time.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Energy Charge	$0.06493~~0.05481~~	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. ~~The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~
5. ~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.
6. ~~The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~
7. ~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.
8. ~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. The Customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

5. Direct Access Customers are not eligible for this rate schedule.

AVAILABILITY

This rate schedule is applicable to those portions of cities, towns and unincorporated communities in which the Company does a general retail electric business and where the Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered after December 1, 2021.

DESCRIPTION

E-68 is a rate that is applicable for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of Company's facilities.

TIME PERIOD

Dusk: The time between sunset and full night when photocontrol senses the lack of sufficient sunlight and turns on the lights.

Dawn: The time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

CHARGES

The monthly bill will consist of the fixture and energy charges, plus adjustments:

I. FIXTURES (Includes Mounting Arm, if applicable)

Fixture Equipment Class	Fixture Cost Range (per unit)	Investment by Company Monthly Rate	Investment by Others Monthly Rate
A	$ 1 - $ 430	$ 6.77 ~~5.72~~	$ 2.06 ~~1.75~~
B	$ 431 - $ 520	$ 8.25 ~~6.97~~	$ 2.50 ~~2.12~~
C	$ 521 - $ 640	$ 9.90 ~~8.36~~	$ 3.06 ~~2.60~~
D	$ 641 - $ 820	$ 11.83 ~~9.99~~	$ 3.92 ~~3.32~~
E	$ 821 - $ 910	$ 14.98 ~~12.64~~	$ 4.35 ~~3.68~~
F	$ 911 - $ 1,010	$ 16.67 ~~14.07~~	$ 4.82 ~~4.08~~
G	$ 1,011 - $ 1,110	$ 18.23 ~~15.38~~	$ 5.31 ~~4.49~~
H	$ 1,111 - $ 1,250	$ 20.67 ~~17.44~~	$ 5.96 ~~5.04~~
I	$ 1,251 - $ 1,520	$ 23.00 ~~19.40~~	$ 7.24 ~~6.12~~
J	$ 1,521 - $ 1,670	$ 28.04 ~~23.65~~	$ 7.96 ~~6.73~~
K	$ 1,671 - $ 1,850	$ 31.17 ~~26.29~~	$ 8.82 ~~7.45~~

Note: Equipment cost greater than $1,850 shall be Customer owned.

II. ENERGY (Includes Generation, T&D, RCS & SBC)

Monthly energy charges for new lighting fixtures will be determined by the Company using the following method:

kWh = Fixture Wattage x 344 Usage Hours

Generation = kWh per month x $
0.07856

~~0.06621~~

T&D, RCS, System Benefits = kWh per month x $
0.03182

~~0.02682~~

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.

2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the Customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.

3. Listed kWh reflects the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy, and adjustment charges.

4. kWh is determined by the company based on the rated wattage of the equipment and an established average hourly usage per month.

5. The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the Customer provides earthwork and conduit (excluding the underground to overhead transition).

III. POLES

				CHARGES	
			Height	Investment by Company	Investment by Others
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$ 15.21 ~~12.84~~	$ 2.08 ~~1.77~~
			22 ft.	$ 17.12 ~~14.45~~	$ 2.34 ~~1.99~~
			25 ft.	$ 18.54 ~~15.64~~	$ 2.54 ~~2.16~~
			30 ft.	$ 21.29 ~~17.96~~	$ 2.91 ~~2.47~~
			32 ft.	$ 22.37 ~~18.87~~	$ 2.95 ~~2.50~~
		2 Simplex Adapters	12 ft.	$ 16.22 ~~13.69~~	$ 2.22 ~~1.89~~
			22 ft.	$ 18.64 ~~15.73~~	$ 2.55 ~~2.17~~
			25 ft.	$ 19.45 ~~16.41~~	$ 2.66 ~~2.26~~
			30 ft.	$ 22.61 ~~19.07~~	$ 3.10 ~~2.63~~
			32 ft.	$ 24.11 ~~20.34~~	$ 3.31 ~~2.81~~
	Square Steel	5"	13 ft.	$ 17.44 ~~14.72~~	$ 2.38 ~~2.02~~
			15 ft.	$ 15.58 ~~13.15~~	$ 2.13 ~~1.81~~
			23 ft.	$ 18.49 ~~15.60~~	$ 2.53 ~~2.15~~
			25 ft.	$ 20.33 ~~17.15~~	$ 2.78 ~~2.36~~
			28 ft.	$ 22.57 ~~19.04~~	$ 3.09 ~~2.62~~
			32 ft.	$ 22.44 ~~18.93~~	$ 3.08 ~~2.61~~
	Concrete		12 ft.	$ 52.03 ~~43.87~~	$ 7.15 ~~6.04~~
	Fiberglass		12 ft.	$ 44.06 ~~37.15~~	$ 6.04 ~~5.11~~
	Decorative Transit	4"	16 ft.	$ 42.95 ~~36.22~~	$ 5.91 ~~5.00~~
	Decorative Transit	6"	30 ft.	$ 82.95 ~~69.93~~	$ 11.41 ~~9.63~~
	Hinged Poles	Square	15 ft.	$ 16.50 ~~13.92~~	$ 1.33 ~~1.14~~
		Round	19 ft.	$ 14.92 ~~12.59~~	$ 1.20 ~~1.03~~
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	$ 14.63 ~~12.35~~	$ 1.99 ~~1.69~~
			22 ft.	$ 16.55 ~~13.97~~	$ 2.26 ~~1.92~~
			25 ft.	$ 17.94 ~~15.14~~	$ 2.46 ~~2.09~~
			30 ft.	$ 20.72 ~~17.48~~	$ 2.85 ~~2.42~~
			32 ft.	$ 21.78 ~~18.37~~	$ 2.98 ~~2.53~~
		2 Simplex Adapters	12 ft.	$ 15.63 ~~13.19~~	$ 2.13 ~~1.81~~
			22 ft.	$ 17.47 ~~14.74~~	$ 2.38 ~~2.02~~
			25 ft.	$ 18.86 ~~15.91~~	$ 2.57 ~~2.18~~
			30 ft.	$ 22.02 ~~18.58~~	$ 3.01 ~~2.55~~
			32 ft.	$ 23.52 ~~19.84~~	$ 3.22 ~~2.73~~
		3 Bolt Arm	32 ft.	$ 27.03 ~~22.80~~	$ 3.69 ~~3.13~~
	Square Steel	5"	13 ft.	$ 16.88 ~~14.24~~	$ 2.32 ~~1.97~~
			15 ft.	$ 17.25 ~~14.56~~	$ 2.34 ~~1.99~~
			23 ft.	$ 17.91 ~~15.11~~	$ 2.46 ~~2.09~~
			25 ft.	$ 19.76 ~~16.67~~	$ 2.72 ~~2.31~~
			28 ft.	$ 21.95 ~~18.52~~	$ 3.01 ~~2.55~~
			32 ft.	$ 22.80 ~~19.23~~	$ 3.10 ~~2.63~~

III. POLES (cont.)

				CHARGES	
			Height	Investment by Company	Investment by Others
C. Direct Bury	Round Steel		19 ft.	$ 23.03 ~~19.43~~	$ 3.16 ~~2.68~~
			30 ft.	$ 17.98 ~~15.17~~	$ 3.31 ~~2.81~~
			38 ft.	$ 21.94 ~~18.51~~	$ 3.40 ~~2.88~~
		Self	40 ft.	$ 27.03 ~~22.80~~	$ 4.26 ~~3.61~~
		Stepped	25 ft.	$ 62.21 ~~52.45~~	$ 5.06 ~~4.28~~
			32 ft.	$ 65.52 ~~55.24~~	$ 5.33 ~~4.51~~
			49 ft.	$ 81.34 ~~68.57~~	$ 11.19 ~~9.45~~
	Square Steel	4"	34 ft.	$ 19.84 ~~16.74~~	$ 3.42 ~~2.90~~
		5"	20 ft.	$ 18.84 ~~15.90~~	$ 3.10 ~~2.63~~
			30 ft.	$ 19.64 ~~16.57~~	$ 3.22 ~~2.73~~
			38 ft.	$ 21.31 ~~17.98~~	$ 3.68 ~~3.12~~
		8"	28 ft.	$ 35.59 ~~30.01~~	$ 2.87 ~~2.44~~
			32 ft.	$ 37.20 ~~31.37~~	$ 3.03 ~~2.57~~
	Decorative Transit		41 ft 6"	$ 25.61 ~~21.60~~	$ 3.74 ~~3.17~~
	Decorative Transit		47 ft.	$ 31.91 ~~26.91~~	$ 4.68 ~~3.96~~
	Steel Distribution Pole (for lighting only)		35 ft.	$ 29.45 ~~24.84~~	$ 3.86 ~~3.27~~
D. Post Top	Decorative Transit Anchor Base		16 ft.	$ 43.88 ~~37.00~~	$ 6.01 ~~5.08~~
	Gray Steel/Fiberglass		23 ft.	$ 15.20 ~~12.83~~	$ 2.48 ~~2.11~~
	Black Steel		23 ft.	$ 16.76 ~~14.14~~	$ 2.74 ~~2.33~~
E. Existing distribution pole suitable for streetlight use				$ 1.83 ~~1.56~~	--
F. Wood	Wood Poles		30 ft.	$ 11.20	
			35 ft.	$ 11.20	
			40 ft.	$ 16.00	

IV. ANCHOR BASE

			CHARGES	
		Height	Investment by Company	Investment by Others
A. Flush		4 ft.	$ 12.38 ~~10.45~~	$ 1.69 ~~1.44~~
		6 ft.	$ 14.78 ~~12.47~~	$ 2.54 ~~2.16~~
B. Pedestal		8 ft.	$ 16.93 ~~14.29~~	$ 2.93 ~~2.49~~
	For 32' Round Steel Pole only	4 ft. 6"	$ 11.74 ~~9.91~~	$ 2.01 ~~1.71~~

V. CHARGES FOR OPTIONAL OR ADDITIONAL COMPANY OWNED EQUIPMENT

Underground Circuit Charges	
a. Per foot of cable, installed under paving	$ 0.19757 ~~0.16652~~
b. Per foot of cable, not installed under paving	$ 0.06973 ~~0.05877~~

TRIP CHARGE

A $150.00 trip charge per light will be charged when a Customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street lighting equipment.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Standard charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.

~~6.~~5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~7.~~6. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM

~~8.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

SERVICE DETAILS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.

2. The Customer's bill will not be reduced due to photocontrol or cable repair or replacement outages.

3. Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

4. The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the Customer. When the extension is underground, the customer will provide earthwork as specified in the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

    a. Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

5. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill. In addition, service may be subject to special terms and conditions as provided for in a Customer contract, maintenance, or service agreement.

AVAILABILITY

This rate schedule is available to Customers that pump water for ~~non-~~agricultural irrigation or municipal water service.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge, and an energy charge. Rate Schedule E-221 is a special rate for Customers pumping irrigation water or for water utilities pumping potable water to service the citizens of a city, town, or unincorporated community.

CHARGES

The monthly bill will consist of the following charges or a minimum bill, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
Self-Contained Meter	$ 1.389 ~~1.110~~	per day
Instrument Rated Meter	$ 2.418 ~~1.932~~	per day
Primary Meter	$ 5.925 ~~4.733~~	per day

Demand Charge	$ 5.232 ~~4.651~~	per- kW

Energy Charge for the first 240 kWh	$ 0.13391 ~~0.10117~~	per kWh
Energy Charge for all additional kWh	$ 0.09244 ~~0.06991~~	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 ~~1.932~~ per day plus $ 5.232 ~~4.651~~ per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or

2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603 ~~0.482~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740 ~~0.591~~	per day
Instrument Rate Meter	$ 1.769 ~~1.413~~	per day
Primary Meter	$ 5.276 ~~4.214~~	per day

Demand Charge Components		
Generation	$ 1.248 ~~0.941~~	per kW
Delivery	$ 1.114 ~~0.840~~	per kW
Transmission	$ 2.870 ~~2.870~~	per kW

Energy Charge Components		
Generation for the first 240 kWh	$ 0.09626 ~~0.07256~~	per kWh
Generation for all additional kWh	$ 0.07670 ~~0.05781~~	per kWh
Delivery for the first 240 kWh	$ 0.03378 ~~0.02546~~	per kWh
Delivery for all additional kWh	$ 0.01187 ~~0.00895~~	per kWh
System Benefits (all kWh)	$ 0.00387 ~~0.00315~~	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown below.

4. Electric service is supplied at a single point of delivery and measured through a single meter. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.

AVAILABILITY

This rate schedule is available to Standard Offer Customers for service to water pumps for the purpose of agricultural irrigation.

DESCRIPTION

Rate Schedule E-221 AG is a rate schedule for agricultural Customers using a pump to move water for agricultural irrigation. This rate has three parts: a basic service charge, a demand charge, and an energy charge.

CHARGES

The monthly bill will consist of the following charges or a minimum bill, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
Self-Contained Meter	$ 1.389 ~~1.110~~	per day
Instrument Rated Meter	$ 2.418 ~~1.932~~	per day
Primary Meter	$ 5.925 ~~4.733~~	per day

Demand Charge	$ 4.769 ~~4.302~~	per kW

Energy Charge for the first 240 kWh	$ 0.11988 ~~0.09060~~	per kWh
Energy Charge for all additional kWh	$ 0.08751 ~~0.06620~~	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 ~~1.932~~ per day plus $ 4.769 ~~4.302~~ per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or

2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603 ~~0.482~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740 ~~0.591~~	per day
Instrument Rate Meter	$ 1.769 ~~1.413~~	per day
Primary Meter	$ 5.276 ~~4.214~~	per day

Demand Charge Components		
Generation	$ 1.248 ~~0.941~~	per kW
Delivery	$ 0.651 ~~0.491~~	per kW
Transmission	$ 2.870 ~~2.870~~	per kW

Energy Charge Components		
Generation for the first 240 kWh	$ 0.09626 ~~0.07256~~	per kWh
Generation for all additional kWh	$ 0.07669 ~~0.05781~~	per kWh
Delivery for the first 240 kWh	$ 0.01975 ~~0.01489~~	per kWh
Delivery for all additional kWh	$ 0.00695 ~~0.00524~~	per kWh
System Benefits (all kWh)	$ 0.00387 ~~0.00315~~	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements, the Customer will pay the cost to install and remove the equipment.

If the load does not meet the power factor requirements, the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

DEFINITIONS

1. The term Agricultural is defined as the practice of farming, including the cultivation of soil for the production of crops.

2. The term Irrigation is defined as the watering of land by artificial means to foster plant growth.

3. The term Pump is defined as the mechanical device using suction or pressure to raise or move water.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. This schedule is not applicable to breakdown, standby, supplemental, residential, or resale service.

5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.

6. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

7. Direct Access Customers are not eligible for this rate schedule.

8. This rate schedule is not available to service for which rate schedules E-34 or E-35 is applicable.

AVAILABILITY

This rate schedule is available to Standard Offer Customers for service to a water pump for the purpose of Agricultural Irrigation.

DESCRIPTION

Rate Schedule E-221 AG TOU is a rate schedule for Agricultural Customers using a pump to move water for Agricultural Irrigation. This rate has three parts: a basic service charge, a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by both season (summer or winter) and the time of day that the energy is used (On-Peak, Off-Peak, or Super Off-peak).

TIME PERIOD

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Super Off Peak:	10:00 am – 3:00 pm (Winter only)
Summer months:	May through October billing cycle
Winter months:	November through April billing cycle

CHARGES

The monthly bill will consist of the following charges or a minimum bill, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
Self-Contained Meter	$ 1.389 ~~1.110~~	per day
Instrument Rated Meter	$ 2.418 ~~1.932~~	per day
Primary Meter	$ 5.925 ~~4.733~~	per day

Demand Charge – On-Peak	$ 5.018 ~~4.489~~	per kW

	Summer	Winter	
Energy Charge On-Peak	$ 0.12804 ~~0.09674~~	$ 0.12804 ~~0.09674~~	per kWh
Energy Charge Off-Peak	$ 0.08786 ~~0.06646~~	$ 0.08786 ~~0.06646~~	per kWh
Energy Charge Super Off-Peak		$ 0.04038 ~~0.03067~~	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 ~~1.932~~ per day plus $ 5.018 ~~4.489~~ per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or

2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603 ~~0.482~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740 ~~0.591~~	per day
Instrument Rate Meter	$ 1.769 ~~1.413~~	per day
Primary Meter	$ 5.276 ~~4.214~~	per day

Demand Charge Components	On-Peak	
Generation	$ 1.276 ~~0.962~~	per kW
Delivery	$ 0.872 ~~0.657~~	per kW
Transmission	$ 2.870 ~~2.870~~	per kW

Energy Charge Components	Summer	Winter	
Generation Charge On-Peak	$ 0.10294 ~~0.07759~~	$ 0.10294 ~~0.07759~~	per kWh
Generation Charge Off-peak	$ 0.06276 ~~0.04731~~	$ 0.06276 ~~0.04731~~	per kWh
Generation Charge Super Off-peak		$ 0.02259 ~~0.01703~~	per kWh
Delivery Charge On-Peak	$ 0.02123 ~~0.01600~~	$ 0.02123 ~~0.01600~~	per kWh
Delivery Charge Off-peak	$ 0.02123 ~~0.01600~~	$ 0.02123 ~~0.01600~~	per kWh
Delivery Charge Super Off-peak		$ 0.01392 ~~0.01049~~	per kWh
System Benefits (all kWh)	$ 0.00387 ~~0.00315~~	$ 0.00387 ~~0.00315~~	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

DEFINITIONS

1. The term Agricultural is defined as the practice of farming, including the cultivation of soil for the production of crops.

2. The term Irrigation is defined as the watering of land by artificial means to foster plant growth.

3. The term Pump is defined as the mechanical device using suction or pressure to raise or move water.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.
5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.
6. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.
7. Direct Access Customers are not eligible for this rate schedule.
8. This rate schedule is not available to service for which rate schedules E-34 or E-35 is applicable.

AVAILABILITY

This rate schedule is available to Customers that pump water for ~~non-~~agricultural~~,~~ irrigation, or municipal water service.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge, and an energy charge. Both the demand and energy charge vary depending on the ~~time~~ time-~~of~~-of-day energy is used. Rate Schedule E-221-8T is a special rate for Customers pumping agricultural irrigation water or for water utilities pumping potable water to service the citizens of a city, town, or unincorporated community.

TIME PERIODS

On-Peak hours:	11:00 a.m. - 9:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

CHARGES

The monthly bill will consist of the following charges, or a minimum bill as discussed below, whichever is greater, plus adjustments:

Bundled Charges

Basic Service Charge		
Self-Contained Meter	$ 1.389 ~~1.110~~	per day
Instrument Rated Meter	$ 2.418 ~~1.932~~	per day
Primary Meter	$ 5.925 ~~4.733~~	per day

Demand Charge On-Peak	$ 7.572 ~~6.414~~	per kW
Demand Charge Off-Peak	$ 5.534 ~~4.171~~	per kW

Energy Charge On-Peak	$ 0.11287 ~~0.08531~~	per kWh
Energy Charge Off-Peak	$ 0.06070 ~~0.04598~~	per kWh

MINIMUM BILL

The minimum bill will not be less than $ 2.418 ~~1.932~~ per day plus $ 7.572 ~~6.414~~ per kW multiplied by the higher of:

1. The highest kW used during the 12 months ending with the current month, or
2. the minimum kW specified in the Electric Service Agreement, if applicable.

For billing purposes, the kW used in this rate schedule will be based on the average kW used during the 15-minute period of maximum use during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$ 0.603 ~~0.482~~	per day
Billing	$ 0.035 ~~0.028~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Metering (only one applies)		
Self-Contained Meter	$ 0.740 ~~0.591~~	per day
Instrument Rate Meter	$ 1.769 ~~1.413~~	per day
Primary Meter	$ 5.276 ~~4.214~~	per day

Demand Charge Components		
Generation on-peak	$ 2.769 ~~2.087~~	per kW
Generation off-peak	$ 3.601 ~~2.714~~	per kW
Delivery on-peak	$ 1.933 ~~1.457~~	per kW
Delivery off-peak	$ 1.933 ~~1.457~~	per kW
Transmission on-peak	$ 2.870 ~~2.870~~	per kW

Energy Charge Components		
Generation on-peak	$ 0.10682 ~~0.08052~~	per kWh
Generation off-peak	$ 0.05465 ~~0.04119~~	per kWh
Delivery (all kWh)	$ 0.00218 ~~0.00164~~	per kWh
System Benefits (all kWh)	$ 0.00387 ~~0.00315~~	per kWh

ADJUSTMENTS

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

~~9.~~7. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
PPR	Preference power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown below.

5. Customers taking service under this rate schedule may be subject to an Electric Service Agreement.

RATE SCHEDULE GS-SCHOOLS L
GENERAL SERVICE TIME OF USE (401 kW +)
ELEMENTARY AND SECONDARY SCHOOLS

AVAILABILITY

This rate schedule is available to private and public elementary and secondary schools (K-12) whose average monthly maximum demand is greater than 400 kW and less than 3,000 kW per month.

DESCRIPTION

This rate schedule is specifically for K-12 educational facilities and is available only to the actual meter of the school that is connected to classrooms or facilities directly related to teaching. The rate does not apply to separate facilities such as administration offices, or bus depots. This rate schedule is a three-part rate: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule GS-SCHOOLS M or GS-SCHOOLS L based on the average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer:	May through October billing cycles
Winter:	November through April billing cycles

Summer Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

Winter Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Rates

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 3.698 ~~2.938~~	per day
For service through Instrument-Rated Meters	$ 4.738 ~~3.764~~	per day
For service at Primary Voltage	$ 8.275 ~~6.574~~	per day
For service at Transmission Voltage	$ 46.760 ~~37.150~~	per day

Demand Charges			
Secondary Service	First 100 kW	$ 13.376 ~~11.217~~	per kW
	All additional kW	$ 7.452 ~~6.510~~	per kW
Primary Service	First 100 kW	$ 12.457 ~~10.487~~	per kW
	All additional kW	$ 6.538 ~~5.784~~	per kW
Transmission Service	First 100 kW	$ 9.873 ~~8.434~~	per kW
	All additional kW	$ 3.946 ~~3.725~~	per kW

Energy Charges			
	Summer Peak	Winter	
On-Peak	$ 0.20238 ~~0.16086~~	$ 0.13543 ~~0.10767~~	per kWh
Off-Peak	$ 0.08281 ~~0.06587~~	$ 0.05540 ~~0.04409~~	per kWh

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule will be based on the maximum demand kW used during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the month.

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts	$ 2.905 ~~2.308~~	per day
Billing	$ 0.037 ~~0.029~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day
Meter Charge (only one applies)		
Self-Contained Meter	$ 0.745 ~~0.592~~	per day
Instrument-Rated Meter	$ 1.785 ~~1.418~~	per day
Primary Voltage Meter	$ 5.322 ~~4.228~~	per day
Transmission Voltage Meter	$ 43.807 ~~34.804~~	per day

Demand Charge Components
(only one service voltage applies in addition to the Transmission and Ancillary charge)

Transmission & Ancillary		$ 2.870 ~~2.870~~	per kW
Delivery - Secondary Service	First 100 kW	$ 10.506 ~~8.347~~	per kW
	All additional kW	$ 4.582 ~~3.640~~	per kW
Delivery - Primary Service	First 100 kW	$ 9.587 ~~7.617~~	per kW
	All additional kW	$ 3.668 ~~2.914~~	per kW
Delivery - Transmission Service	First 100 kW	$ 7.003 ~~5.564~~	per kW
	All additional kW	$ 1.076 ~~0.855~~	per kW

Energy Charge Components

	Summer Peak	Winter	
Generation On-Peak	$ 0.18021 ~~0.14317~~	$ 0.11326 ~~0.08998~~	per kWh
Generation Off-Peak	$ 0.06064 ~~0.04818~~	$ 0.03323 ~~0.02640~~	per kWh

Delivery	$ 0.01830 ~~0.01454~~	per kWh
System Benefits	$ 0.00387 ~~0.00315~~	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load does not meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

5. Direct Access Customers are not eligible for this rate schedule.

6. Service under this schedule is generally provided at secondary voltage; primary voltage when the Customer owns the distribution transformer(s); or transmission voltage.

RATE SCHEDULE GS-SCHOOLS M
GENERAL SERVICE TIME-OF-USE (0 kW – 400 kW)
ELEMENTARY AND SECONDARY SCHOOLS

AVAILABILITY

This rate schedule is available to private and public elementary and secondary schools (K-12) whose average monthly maximum demand is less than or equal to 400 kW per month.

DESCRIPTION

This rate schedule is specifically for K-12 educational facilities and is available only to the actual meter of the school that is connected to classrooms or facilities directly related to teaching. The rate does not apply to separate facilities such as administration offices, or bus depots. This rate schedule has three parts: a basic service charge; a demand charge for the average demand (kW) supplied during the 15-minute period of maximum use during the month; and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule GS-SCHOOLS M or GS-SCHOOLS L based on the average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIODS

Summer:	May through October billing cycles
Winter:	November through April Billing Cycles

Summer Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

Winter Hours

On-Peak hours:	3:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak hours:	All remaining hours

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Rates

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 1.393 ~~1.115~~	per day
For service through Instrument-Rated Meters	$ 2.424 ~~1.941~~	per day
For service at Primary Voltage	$ 5.937 ~~4.753~~	per day
For service at Transmission Voltage	$ 44.158 ~~35.352~~	per day

Demand Charges			
Secondary Service	First 100 kW	$ 13.606 ~~11.465~~	per kW
	All additional kW	$ 7.589 ~~6.648~~	per kW
Primary Service	First 100 kW	$ 12.679 ~~10.723~~	per kW
	All additional kW	$ 6.660 ~~5.904~~	per kW
Transmission Service	First 100 kW	$ 10.050 ~~8.618~~	per kW
	All additional kW	$ 4.033 ~~3.801~~	per kW

Energy Charges:			
	Summer Peak	Winter	
On-Peak	$ 0.22343 ~~0.17892~~	$ 0.14956 ~~0.11978~~	per kWh
Off-Peak	$ 0.08360 ~~0.06698~~	$ 0.05597 ~~0.04486~~	per kWh

For billing purposes, including determination of monthly maximum demands, the kW used in this rate schedule shall be based on the maximum demand kW used during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the month.

Unbundled Components of the Bundled Charges

Bundled charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts	$ 0.605 ~~0.484~~	per day
Billing	$ 0.036 ~~0.029~~	per day
Meter Reading	$ 0.011 ~~0.009~~	per day

Meter Charge (only one applies)		
Self-Contained Meter	$ 0.741 ~~0.593~~	per day
Instrument-Rated Meter	$ 1.772 ~~1.419~~	per day
Primary Voltage Meter	$ 5.285 ~~4.231~~	per day
Transmission Voltage Meter	$ 43.506 ~~34.830~~	per day

Demand Charge Components
(only one service voltage applies in addition to the Transmission and Ancillary charge)

Transmission & Ancillary		$ 2.870	per kW
Delivery - Secondary Service	First 100 kW	$ 10.736 ~~8.595~~	per kW
	All additional kW	$ 4.719 ~~3.778~~	per kW
Delivery - Primary Service	First 100 kW	$ 9.809 ~~7.853~~	per kW
	All additional kW	$ 3.790 ~~3.034~~	per kW
Delivery - Transmission Service	First 100 kW	$ 7.180 ~~5.748~~	per kW
	All additional kW	$ 1.163 ~~0.931~~	per kW

Energy Charge Components

	Summer Peak	Winter	
Generation On-Peak	$ 0.19205 ~~0.15375~~	$ 0.11818 ~~0.09461~~	per kWh
Generation Off-Peak	$ 0.05222 ~~0.04181~~	$ 0.02459 ~~0.01969~~	per kWh

Delivery	$ 0.02751 ~~0.02202~~	per kWh
System Benefits	$ 0.00387 ~~0.00315~~	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

~~4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.~~

~~5.~~4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1

~~6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.~~

~~7.~~5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

~~8.~~6. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – -Net Metering
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SD-1	Schools Discount
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. Direct Access Customers are not eligible for this rate schedule.

5. The contract period for all Customers receiving service under this rate schedule will be one (1) year at the Company's option.

6. Service under this schedule is generally provided at secondary voltage; primary voltage when the Customer owns the distribution transformer(s)~~,~~ or transmission voltage.

ADJUSTMENT SCHEDULE DSMAC-1
DEMAND SIDE MANAGEMENT ADJUSTMENT

AVAILABILITY

The Demand Side Management Adjustment Charge (DSMAC) applies to all Customer service accounts.

DESCRIPTION

The monthly DSMAC charge is used to recover the cost of Commission-approved programs and services to meet compliance with Arizona's Energy Efficiency Standard and lost fixed costs associated with energy efficiency programs and renewable programs that are not collected through base rates.

CHARGES

The monthly charge for each service account will be calculated at the following rate:

For all Residential Customers:		
All kWh	$0.~~001374~~XXXXXXX	per kWh

For General Service Customers not billed a demand charge:		
All kWh	$0.~~001374~~XXXXXX	per kWh

For General Service Customers billed a demand charge:		
All billed kW or billed on-peak kW for TOU customers	$0.~~508~~XXX	per kW

~~SELF-DIRECTION~~

~~Qualifying Customers have an option under Adjustment Schedule DSMAC-1 under which the Customer may reserve DSMAC contributions, less administrative and other program costs, for exclusive use to fund qualifying DSM projects at the Customer's facilities. To qualify, the Customer must:~~

~~1. Use a minimum of 40 million kWh per calendar year, based on aggregation of all of the Customer's accounts;~~

~~2. Notify APS on or before December 1st in each year the Customer wishes to self-direct; and~~

~~3. Upon notification and verification of eligibility by APS, 85% of the Customer's DSM charges will be reserved for tracking purposes for the Customer's future energy efficiency project(s),~~

~~which must be completed within two years. The remaining 15% will be retained to cover self-direction program administration costs.~~

~~For further details regarding Self-Direction provisions, please see Arizona Corporation Commission Decision No. 71448, Attachment C to the Settlement Agreement, which may be modified from time to time with Commission approval.~~

SERVICE DETAILS

1. The DSMAC is calculated annually and will go into effect upon approval of the Company's annual DSM Implementation Plan and will remain in effect for the following 12-month period unless otherwise ordered by the Commission.

2. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

3. Charges under Adjustment Schedules REAC-1 and DSMAC-1 may be combined and shown on the "Environmental Benefits Surcharge" line of the Customer's monthly bill.

ADJUSTMENT SCHEDULE EIS
ENVIRONMENTAL IMPROVEMENT SURCHARGE

~~APPLICATION~~

~~The Environmental Improvement Surcharge (EIS) will be applied monthly to all Customer bills, except for those Customers served under Rate Schedule E-36 XL and AG-X.~~

~~DESCRIPTION~~

~~The EIS adjustment recovers costs associated with investment and expenses for environmental improvements at the Company's generation facilities that the Arizona Corporation Commission (Commission) has approved and the Company is not already recovering in base rates. Ongoing environmental improvement projects designed to comply with upcoming environmental standards required by federal, state, tribal, or local laws or regulations are also approved for recovery.~~

~~CHARGES~~

~~The charge will be calculated at the following rate:~~

~~EIS Adjustment Charge~~	~~$0.000403~~	~~per kWh~~

~~SERVICE DETAILS~~

~~1. The EIS adjustment charge will be calculated annually and will go into effect with the first billing cycle in April (without proration) and will remain in effect for the following 12-month period unless otherwise ordered by the Commission.~~

~~2. All terms and charges in the customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.~~

This adjustor is no longer applicable to any rate structure and is cancelled as of XXXX in Decision No. XXXXX.

ADJUSTMENT SCHEDULE LFCR
LOST FIXED COST RECOVERY MECHANISM

~~APPLICATION~~

~~The Lost Fixed Cost Recovery (LFCR) Mechanism applies to all Customer service accounts, except for Customers served under Rate Schedules E-30, E-32L, E-32 TOU L, E-34, E-35, E-36XL, XHLF and unmetered lighting schedules including E-45, E-47, E-58, E-59, E-68 and Contract 12.~~

~~DESCRIPTION~~

~~The LFCR adjustment charge recovers fixed costs of providing service that are not recovered due to mandated energy efficiency and renewable resource requirements. For Customers on a three-part (demand) rate, the LFCR charge is calculated on a per kW rate each month. For Customers on a two-part (energy) rate, the LFCR charge is calculated on a per kWh rate each month.~~

~~CHARGES~~

~~The monthly charge for each service account will be calculated at the following rates:~~

~~For Customers on a demand rate:~~	~~$0.775~~	~~per kW per month~~
~~For Customers on an energy-only rate:~~	~~$0.00263~~	~~per kWh per month~~

~~SERVICE DETAILS~~

1. ~~The LFCR adjustment charge is calculated annually and will go into effect with the first billing cycle of May (without proration) and will remain in effect for the following 12-month period unless otherwise ordered by the Commission.~~

2. ~~All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.~~

This adjustor is no longer applicable to any rate structure and is cancelled as of XXXX in Decision No. XXXXX.

AVAILABILITY

The Power Supply Adjustment (PSA) applies to all Customer bills with the exception of E-36 XL, AG-X, and Direct Access service.

DESCRIPTION

This adjustment schedule recovers or credits Customer bills for any fuel and purchased power costs that vary from the cost of fuel collected in base rates.

CHARGES

PSA Historical Component	$0.~~012386~~XXXXXX	per kWh
PSA Forward Component	~~(~~$0.~~004842~~XXXXXX~~)~~	per kWh
PSA Transition Component	$0.000000	per kWh

SERVICE DETAILS

1. The PSA Historical Component, PSA Forward Component, and PSA Transition Component are defined in the Company's Power Supply Adjustment Plan of Administration.

2. This adjustment is recalculated on an annual basis, except for the Transition Component which may apply from time to time, and will go into effect with the first billing cycle in February (without proration) and will remain in effect for a 12-month period unless otherwise ordered by the Commission.

3. All terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

ADJUSTMENT SCHEDULE RCDAC-1
RETURNING CUSTOMER DIRECT ACCESS CHARGE

AVAILABILITY

The Returning Customers Direct Access Charge (RCDAC) will apply to Customers, or an aggregated group of Customers, of 3 MW or greater who left Standard Offer or special contract service for competitive generation suppliers and are returning to Standard Offer service.

CHARGES

The RCDAC will be identified in the Electric Service Agreement between the Customer and the Company and will be in addition to any Standard Offer service charges. The charge will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning Customer. The costs associated with serving Customers that are required to enter into RCDAC agreements will be separate from the retail power supply costs subject to recovery through the Power Supply Adjustment.

Types of costs that will be used to develop the RCDAC are incremental Power Supply, Transmission, Ancillary Services and Metering costs as defined in the Returning Customer Direct Access Charge Plan for Administration. These costs will be amortized over an appropriate period to allow for timely recovery. The RCDAC will not be billed longer than 12 months for any individual Customer.

SERVICE DETAILS

1. Customers that have been Direct Access Customers since beginning service from the Company are considered returning Customers for the purposes of this schedule.

2. The RCDAC will only be applied if the Customer wants to return to Standard Offer service and the Company did not include that Customer load in planned resource acquisitions. If the Company is provided one year's advance notice of the Customer's intent to return to Standard Offer service, that Customer will not be assessed the RCDAC charge.

3. APS may create a specific RCDAC in each individual case and require the Customer to enter into a service agreement that specifies the charge, its duration, and how it will be applied and collected. In situations where an aggregated group of Customers wish to return to Standard Offer service, each Customer from the group will be charged the same rate for the same duration and an Electric Service Agreement will be required from each customer.

4. All provisions of the Customer's current applicable rate schedule will apply in addition to this charge.

AVAILABILITY

The Renewable Energy Adjustment Charge (REAC) applies to all Customer service accounts.

DESCRIPTION

The monthly REAC charge recovers expenditures made by the Company to meet compliance with Arizona's Renewable Energy Standard.

CHARGES

The monthly charge for each service account will be calculated at the following rates and surcharge caps:

kWh Charge	$~~0.007812~~X.XXXXXX	per kWh

Surcharge Caps (per service account per month)

Residential Customers	$~~3.00~~XX.XX	per Month
Non-Residential Customers		
Extra-Small and Small	$ XX.XX~~50.00~~	per Month
Medium	$ XX.XX~~200.00~~	per Month
Large	$ XX.XX~~500.00~~	per Month
Extra-Large	$ XX.XX~~2,500.00~~	per Month

Surcharge caps shown above apply to the following:

1. Customers who have not installed an on-site renewable distribution generation system;

2. Customers that installed an on-site renewable distribution generation system prior to July 1, 2012; and

3. Customers that installed an on-site renewable distribution generation system after July 1, 2012 and before February 1, 2013 and did not receive an incentive.

Alternative REAC Charges, Flat Charges, and Minimum Charges

Residential Customers	$ XX.XX~~2.62~~	Flat charge per Month
Non-Residential Customers		
Extra-Small	$ XX.XX~~6.52~~	Minimum charge per Month
	$ XX.XX~~50.00~~	Surcharge cap
Small	$ XX.XX~~32.62~~	Minimum charge per Month
	$ XX.XX~~50.00~~	Surcharge cap
Medium	$ XX.XX~~174.75~~	Flat charge per Month
Large	$ XX.XX~~456.58~~	Flat charge per Month
Extra-Large	$ XX.XX~~2,500.00~~	Flat charge per Month

Flat charges shown above apply to the following:

1. Customers that installed a renewable distributed generation system after July 1, 2012 and received an incentive; and

2. Customers that installed a renewable distributed generation system interconnected to the Company's distribution grid after February 1, 2013, regardless of whether an incentive was received.

Minimum Charges and Surcharge Caps shown above apply to the following:

1. Extra-Small and Small General Service Customers that installed a renewable distributed generation system after July 1, 2012 and received an incentive; and

2. Extra-Small and Small General Service Customers that installed a renewable distributed generation system and interconnected to the Company's distribution grid after February 1, 2013, regardless of whether an incentive was received.

NON-RESIDENTIAL CUSTOMER BILLING CATEGORIES

Non-residential Customers served under the following retail rate schedules will be billed under the surcharge categories shown below:

Retail Rate Schedule	Surcharge Category
E-30, E-32 XS, E-32 XS D, E-32TOU XS, E-45, E-47~~,~~ E-58, E-59, ~~Contract 12,~~ E-67, E-68, Contract 12~~, E-36M (small option)~~	Extra-Small
E-32 S, E-32TOU S	Small
E-32 M, E-32TOU M	Medium
E-32 L, E-32TOU L, ~~E-36M (medium option)~~E-32 L SP, GS-Schools L	Large
E-34, E-35, XHLF, E-36 XL	Extra-Large

For non-residential Customers served under the following rate schedules, the surcharge category will be based on the monthly billing demand as shown below:

Retail Rate Schedule	Monthly Billing Demand	Surcharge Category
E-221, E-221 8T, E-221 AG, E-221 AG TOU, GS-Schools M, E-20	20 kW and less	Extra-Small
E-221, E-221 8T, E-221 AG, E-221 AG TOU, GS-Schools M~~E-221, E-221 8T~~	21 - 100 kW	Small
E-221, E-221 8T, E-221 AG, E-221 AG TOU	101- 400 kW	Medium
E-221, E-221 8T, E-221 AG, E-221 AG TOU	> 400 kW	Large
~~GS-Schools M~~	~~20 kW and less~~	~~Extra-Small~~
GS-Schools M~~GS-Schools M~~	> 100 kW~~21 - 100 kW~~	Medium~~Small~~
~~GS-Schools M~~	~~> 100 kW~~	~~Medium~~
E-20~~E-20~~	> 20 kW~~20 kW and less~~	Small~~Extra-Small~~
~~E-20~~	~~> 20 kW~~	~~Small~~

SERVICE DETAILS

1. The charges will be revised annually, effective on the first billing cycle in January, or as otherwise ordered by the Arizona Corporation Commission, and will not be prorated.

2. All the terms and charges in the customer's rate schedule continue to apply to electric service provided under this adjustment.

3. Charges applied under Adjustment Schedules REAC-1 and DSMAC-1 may be combined and shown on the "Environmental Benefits Surcharge" line of the Customer's monthly bill.

AVAILABILITY

The Self-Directed Renewable Resources (SDR) Adjustment Schedule is available to all Customers who meet the eligibility requirements below.

DESCRIPTION

The SDR is a self-direct option available to Customers that meet the eligibility requirements below. Under the SDR adjustment schedule, Customers may reserve their REAC-1 contributions, less administrative costs, for exclusive use to help fund qualifying renewable projects at the Customer's site.

ELIGIBILITY REQUIREMENTS

1. Funding Eligibility:

    a. The Customer is eligible to receive funds pursuant to this schedule if the total of all REAC related payments made to the Company for the customer's service account or accounts, individually or collectively, total $25,000 or more in any one calendar year (January – December).

    b. Funds collected from the Customer in any one year (the Payment Year) will be available to the Customer for self-directed projects in the following year (the Funding Year). Funds received during the Funding Year will not exceed payments collected by the Company in the Payment Year. In addition, if the Customer has facilities in multiple service territories, only those payments collected by the Company are eligible for SDR funding.

    c. Customers requesting funds for self-directed projects must declare their intention by applying in writing to the Company on or before March 31 of the Payment Year. The application must include a description of the proposed project and its expected cost.

    d. The Customer shall provide at least half of the funds necessary to complete the proposed project, as required by A.A.C. R14-2-1809.B.

2. Project Eligibility:

    a. SDR funds obtained by the Customer from the Company may only be used for projects physically located within the Company's service territory.

b. Projects specified in the Company's Distributed Energy Administration Plan ("DEAP") are eligible for SDR funding. SDR Customers must request incentives no greater than the prescribed incentives specified in the DEAP. If the Customer wishes to apply funds to a project not specified in the DEAP, the Customer must submit documentation detailing project economics and funding requirements.

c. Any project proposed by the Customer must meet the requirements for a Distributed Renewable Energy Resource described in the Arizona Corporation Commission's Renewable Energy Standard Tariff Rules (A.A.C. R14-2-1802.B).

d. For purposes of financing SDR projects, funds provided by the Company may be assigned to third parties. Such assignment will be at the Customer's sole discretion. The Company assumes no liability for third-party assigned funds.

SERVICE DETAILS

1. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

2. All Renewable Energy Credits derived from any project funded through this schedule, including generation and Extra Credit Multipliers, will be applied to satisfy the Company's annual Renewable Energy Standard requirements.

AVAILABILITY

The Transmission Cost Adjustment (TCA) charge applies to all Customer monthly bills.

DESCRIPTION

The TCA allows the Company to recover transmission costs associated with service to retail Customers at the level approved by the Federal Energy Regulatory Commission (FERC) as new transmission rates become effective.

CHARGES

Customer Class	TCA Charge	
Residential	$0.~~000807~~XXXXXX	per kWh
General Service 20 kW or less	$~~(~~0.~~000542~~XXXXXX~~)~~	per kWh
General Service over 20 kW, under 3,000 kW	$~~(~~0.~~295~~XXX~~)~~	per kW
General Service 3,000 kW and over	$~~(~~0.~~690~~XXX~~)~~	per kW

SERVICE DETAILS

1. The TCA will be calculated annually and will go into effect with the first billing cycle in June (without proration) and will remain in effect for the following 12-month period unless otherwise ordered by the Commission.

2. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this adjustment.

APPLICATION

The Tax Expense Adjustor Mechanism (TEAM) will be applied to all Customer monthly bills.

DESCRIPTION

The TEAM allows the Company to pass through to its Customers any income tax effects that materially impact the Company's annual revenue requirements as a result of federal or state income tax legislation.

CHARGES

The charge will be calculated at the following rate:

TEAM Phase I Component	($0.000000)	per kWh
TEAM Phase II Component	$0.000000	per kWh
TEAM Phase III Component	($0.000000)	per kWh

SERVICE DETAILS

1. The TEAM Phase I Component, TEAM Phase II Component, and TEAM Phase III Component are defined in the Company's Tax Expense Adjustment Mechanism Plan of Administration.

2. The TEAM Adjustment Charge will be calculated annually and will go into effect with the first billing cycle in January (without proration) and will remain in effect for the following 12-month period unless otherwise stipulated or ordered by the Commission. The rates calculated from impacts associated with Phase I, Phase II and Phase III will be included on customer bills as a single line item in accordance with the Plan of Administration.

3. AG-X customers will receive 75.64% of the Adjustment Charge, and customers taking service under rate schedules HLF-1, HLF-2, and HLF-3 will receive 86.84% of the Adjustment Charge.

4. All terms and conditions in the Customer's rate schedule continue to apply to electric service provided under this adjustment schedule.

RATE RIDER CPP-RES
CRITICAL PEAK PRICING – RESIDENTIAL

AVAILABILITY

All residential Customers who can reduce the amount of energy used when called upon may volunteer to participate in this rate rider. The Customer must meet the requirements listed in the service details below.

DESCRIPTION

Critical Peak Pricing (CPP) events are specific hours within the summer months when the Company is expecting extreme temperatures, high energy (kWh) usage, high market energy costs, or is experiencing a major generation or transmission outage. Customers on this rate rider agree to use less energy during these CPP events. Energy charges during CPP events are higher than the remainder of the summer On-Peak hours, but the Customer also receives a discount for all energy used during the CPP summer months.

CHARGES

The following charge will be in addition to the On-Peak charge in the Customer's rate schedule:

Charge for energy use during Critical Peak hours	$0.25000	per kWh

The following discount will apply to all non-Critical Peak hours during CPP summer months (June through September):

Energy Discount for summer non-Critical Peak hours	($0.012143)	per kWh

SERVICE DETAILS

1. This rate rider requires the Customer to have a standard AMI meter in place.

2. A Customer cannot be on this CPP rate rider and another demand response program offered by the Company. Customers may participate in this rate rider and the legacy net metering rate rider, but any exported generation during a CPP event will not be applied toward hours in another CPP event.

3. Details of a CPP event are as follows:

a. CPP events will only be scheduled from 3 p.m. to 8 p.m., Monday through Friday in the months of June through September. CPP events will not be scheduled on holidays (Independence Day on July 4th and Labor Day on the first Monday in September).

b. At least 6 and no more than 18 CPP events may be called per calendar year, and each event will last for a period of five hours.

c. Customers will be notified of a CPP event in advance. By 4:00 PM the day prior to the event, the Customer will receive a phone message, e-mail, or text message. The Customer is responsible to watch for this message.

d. Once noticed, a CPP event will not be cancelled.

4. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

RATE RIDER E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Energy Support Program.

DESCRIPTION

The Energy Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the ~~federal~~ Federal ~~poverty~~ Poverty guidelines or those receiving assistance from an APS approved limited income assistance program.

DISCOUNT

The following discount will apply to the Customer's bill, subject to the service details below:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%~~Discount~~	~~25%~~60%	$165	per bill
Greater than 75% up to and including 200%	25%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

~~2. Customers electing to pay with a credit card will receive a bill credit in the amount of their credit card fee applied to their next month's bill.~~

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

~~3.~~4. Customers may not receive discounts under both this rider and Rate Rider E-4 at the same time.

~~4.~~5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER LEGACY E-3
RESIDENTIAL ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the solar grandfathering program and meet the requirements of the Energy Support Program.

DESCRIPTION

The Energy Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program.

Eligibility for this rate rider will be frozen on September 1, 2017. This means no new Customers will be served under this rider on or after that date, and any Customer that discontinues participation in the Energy Support Program or the solar grandfathering program cannot return to this rider at a later date.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider.

FROZEN

RATES

The following discounts will apply to the Customer's bill, subject to the service details below:

For bills with total energy usage of:		
0 kWh to 400 kWh	65% discount	per bill
401 kWh to 800 kWh	45% discount	per bill
801 kWh to 1200 kWh	26% discount	per bill
1201 kWh and above	$31.75	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. Customers may not receive discounts under both this rider and Rate Rider Legacy E-4 at the same time.

3. Customers who leave the grandfathering program are no longer eligible for Rate Rider Legacy E-3~~,~~ but may be served under Rate Rider E-3 if the Customer continues to qualify.

4. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

~~5. Customers electing to pay with a credit card will receive a bill credit in the amount of their credit card fee applied to their next month's bill.~~

FROZEN

RATE RIDER E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the Medical Care Equipment Support Program.

DESCRIPTION

The Medical Care Equipment Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program and who require qualifying life-sustaining medical equipment.

DISCOUNT

The following discount will apply to energy purchased under this rate rider:

Federal Poverty Tiers	Discount %	Maximum Monthly Discount	
0% up to and including 75%~~Discount~~	60%~~35%~~	$165	per bill
Greater than 75% up to and including 200%	35%	$95	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

~~2. Customers electing to pay with a credit card will receive a bill credit in the amount of their credit card fee applied to their next month's bill.~~

2. The maximum monthly discount represents the largest discount available to the customer.

3. Customer's will not receive a discount greater than the monthly bill.

~~3.~~4. Customers may not receive discounts under both this rider and Rate Rider E-3 at the same time.

~~4.~~5. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER LEGACY E-4
RESIDENTIAL MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider is available to residential Customers who qualify for the solar grandfathering program and meet the requirements of the Medical Care Equipment Support Program.

DESCRIPTION

The Medical Care Equipment Support Program provides a monthly bill discount for Customers with a gross monthly household income at or below 200% of the federal poverty guidelines or those receiving assistance from an APS approved limited income assistance program and who require qualifying life-sustaining medical equipment.

Eligibility for this rate rider will be frozen on September 1, 2017. This means no new Customers will be served under this rider on or after that date, and any Customer that discontinues participation in the Medical Care Equipment Support Program or the solar grandfathering program cannot return to this rider at a later date.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider.

FROZEN

RATES

The following discounts will apply to the Customer's bill, subject to the service details below:

For bills with total energy usage of:		
0 kWh to 800 kWh	65% discount	per bill
801 kWh to 1400 kWh	45% discount	per bill
1401 kWh to 2000 kWh	26% discount	per bill
2001 kWh and above	$60.00	per bill

SERVICE DETAILS

1. The discount will be deducted from the monthly bill prior to the application of taxes, regulatory assessment, service schedule charges, and franchise fees.

2. Customers may not receive discounts under both this rider and Rate Rider Legacy E-3 at the same time.

3. Customers who leave the grandfathering program are no longer eligible for Rate Rider Legacy E-4~~,~~ but may be served under Rate Rider E-4 if the Customer continues to qualify.

~~4.~~ All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

~~5.~~4. ~~Customers electing to pay with a credit card will receive a bill credit in the amount of their credit card fee applied to their next month's bill.~~

FROZEN

RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

AVAILABILITY

This rate rider is available to Customers that qualify for the residential solar grandfathering program. It may be used in conjunction with the residential Legacy rate schedules for distributed generation systems.

This rate rider is frozen effective September 1, 2017. This means a residential Customer that is already taking service under this rate rider before that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider. Instead, the residential Customer will be served under an applicable retail rate of their choice and Rate Rider RCP, or a subsequent replacement rider.

FROZEN

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program. A partial requirements Customer has on-site generation that serves some of their electrical requirements and relies on the Company for additional electrical services. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods, i.e. on-peak export energy will be netted against on-peak energy from the Company and vice-versa, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December billing cycle, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

BILLING DETAILS

1. All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for the remaining export energy at the purchase price.

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to September 1, 2017 and otherwise qualify for this rate rider may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company before September 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application, and otherwise qualify for this rate rider, may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

FROZEN

3. The grandfathering period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternate grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply if applicable.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

FROZEN

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection or purchase agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

    a. Provides part of the Customer's energy requirements at the site where the system is installed;

b. Uses renewable resources, as defined by the Arizona Corporation Commission, to generate energy; and

c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

FROZEN

RATE RIDER LEGACY LFCR DG
LEGACY ADJUSTMENT FOR DISTRIBUTED GENERATION

AVAILABILITY

This rate rider is applied to Customers that qualify for the residential solar grandfathering program and interconnected an on-site renewable distributed generation system to the Company's distribution grid after January 1, 2014. The Legacy LFCR DG Rate Rider does not apply to residential Customers on Rate Schedules Legacy ECT-1R or Legacy ECT-2.

This rate rider is frozen beginning on September 1, 2017. This means no new Customers will be served under this rider on or after that date. This rider will apply to eligible Customers through the 20-year period from the date their solar generator was interconnected to the Company's distribution grid. Charges shown on this schedule may change.

DESCRIPTION

This rate rider recovers a portion of the lost fixed cost revenue that results from the net metering of on-site distributed generation from certain Customers on Net Metering Rate Rider Legacy EPR-6.

CHARGES

The following charges will be applied to the monthly bill in addition to the charges in the Customer's rate schedule:

LFCR DG Charge	$0.700	per kW-DC of generation
Generators not registered with APS	$3.000	per kW-DC of generation

FROZEN

SERVICE DETAILS

1. Monthly charges will be applied to the nameplate kW-DC power rating of the on-site distributed generation system.

2. Any Customer that does not register an on-site distributed generation system with APS through the application and interconnection process when that distributed generation system was installed will be charged the Generators not registered with APS charge.

3. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

RATE RIDER GPS-1
GREEN POWER BLOCK SCHEDULE

AVAILABILITY

This rate rider is available to any Customer who wants to purchase energy specifically generated from renewable resources.

DESCRIPTION

This rate rider allows a Customer to purchase a specific amount of energy (kWh) from the Company that has been generated by a renewable resource. This energy is known as Green Power, and may be generated from any resource designated by the Arizona Corporation Commission as renewable.

Purchases under this rate rider are for 100 kWh blocks of Green Power per month.

CHARGES

The following charge will apply to energy purchased under this rate rider in addition to the charges in the Customer's rate schedule:

Energy Charge	$1.02	per block of 100 kWh

SERVICE DETAILS

1. Green Power may be generated from Company-owned renewable resources, or from a renewable resource that the Company has purchased energy from, and is delivered through the Company's distribution grid.

2. Customers subscribe to a specific number of blocks of renewable energy, each of which equal 100 kWh per block. Participation in this rate rider is limited to the Green Power available. The Company may also limit the amount of energy purchased by a single Customer to 5% of the total Green Power available.

3. Customers must subscribe to the desired number of energy blocks for a minimum of one year. If the charge for each block of energy increases during the subscription year, Customers may cancel participation in this rate rider.

4. All the terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

5. Customers cannot take service under more than one Green Power rate rider at the same time.

AVAILABILITY

This rate rider is available to any Customer who wants to purchase energy specifically generated from renewable resources.

DESCRIPTION

This rate rider allows a Customer to purchase a specific amount of energy (kWh) from the Company that has been generated by a renewable resource. This energy is known as Green Power, and may be generated from any resource designated by the Arizona Corporation Commission as renewable.

Purchases of Green Power under this rate rider are for a percentage of total monthly kWh.

CHARGES

The Customer may choose one of the following options under this rate rider in addition to the charges in the Customer's rate schedule:

Option 1: 100% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0102	per kWh

Option 2: 50% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0051	per kWh

Option 3: 35% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0036	per kWh

Option 4: 10% of monthly usage is Green Power		
Energy Charge for all kWh	$0.0010	per kWh

SERVICE DETAILS

1. Green Power may be generated from Company-owned renewable resources, or from a renewable resource that the Company has purchased energy from, and is delivered through the Company's distribution grid.

2. Participation in this rate rider is limited to the Green Power available. The Company may also limit the amount of energy purchased by a single Customer to 5% of the total Green Power available.

3. Customers must subscribe to the desired percentage of energy usage for a minimum of one year. If the energy charge increases during the subscription year, Customers may cancel participation in this rate rider.

4. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

5. Customers cannot take service under more than one Green Power rate rider at the same time.

RATE RIDER GPS-3
GREEN POWER BLOCK SCHEDULE FOR SPECIAL EVENTS

AVAILABILITY

This rate rider is available to any Customer who wants to purchase energy specifically generated from renewable resources.

DESCRIPTION

This rate rider allows a Customer to purchase a specific amount of energy (kWh) from the Company that has been generated by a renewable resource. This energy is known as Green Power, and may be generated from any resource designated by the Arizona Corporation Commission as renewable.

Purchases under this rate rider are for 100 kWh blocks of Green Power during a temporary special event such as concerts, sporting events, and festivals. Minimum purchase shall be $500.00 per transaction.

CHARGES

The following charge will apply to energy purchased under this rate rider in addition to the charges in the Customer's rate schedule:

Energy Charge	$1.02	per block of 100 kWh

This charge will apply for the duration of the special event as requested by the Customer.

SERVICE DETAILS

1. Green Power may be generated from Company-owned renewable resources, or from a renewable resource that the Company has purchased energy from, and is delivered through the Company's distribution grid.

2. Customers request a specific number of blocks of renewable energy, each of which equal 100 kWh per block, to be used during the special event. Participation in this rate rider is limited to the Green Power available. The Company may also limit the amount of energy purchased by a single Customer to 5% of the total Green Power available.

3. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

4. Customers cannot take service under more than one Green Power rate rider at the same time.

RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR NEW ON-SITE SOLAR DISTRIBUTED GENERATION RESOURCE COMPARISON PROXY EXPORT RATE

AVAILABILITY

This rate rider is available to partial requirements residential ~~c~~Customers with qualified on-site solar generation, served under an applicable residential rate. This rate rider may not be used in conjunction with a grandfathered residential Legacy rate schedule or Legacy rate rider.

DESCRIPTION

A residential Customer with solar generation exports power to the grid from time to time when their generation exceeds the load in their home. The Company will meter this export power on an instantaneous basis and provide a monthly bill credit based on the purchase rate in this schedule.

The purchase rates will be determined as follows:

a. An RCP rate will be determined for each annual tranche of new DG Customers, effective September 1 each year or as determined by the Commission without proration. The RCP rate may not be reduced by more than 10% each year.

b. Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before September 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

c. Each Customer's initial RCP rate will be applicable for 10 years from the time of their interconnection.

d. After each Customer's initial 10 year period the bill credit will be based on the purchase rate in effect at that time, and may change from year to year.

Further details are provided in the Resource Comparison Proxy Plan of Administration and Arizona Corporation Commission Decision Nos. 75859, 75932, 76295, ~~and~~ 78317, 78643, and XXXXX.

PURCHASE RATES

The Company will provide a bill credit for the exported energy based on the following purchase rates:

Tranche 2017	September 1, 2017 through September 30, 2018	$0.12900	per kWh
Tranche 2018	October 1, 2018 through September 30, 2019	$0.11610	per kWh
Tranche 2019 & 2020	October 1, 2019 through September 30, 2021	$0.10450	per kWh
Tranche 2021	October 1, 2021 through August 31, 2022	$0.09405	per kWh
Tranche 2022	September 1, 2022 through August 31, 2023	$0.08465	per kWh

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; however, if the outstanding credits exceed $25, the Company will automatically issue a check to the Customer. Otherwise, the bill credits will carry forward to the following year.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. Electricity must be generated using solar photovoltaic panels;
2. The generator must be interconnected to the Company's distribution grid;
3. The generator must be on-site, installed behind the billing meter, and must serve the residential Customer's load.

Systems of any size are subject to the requirements found in the Arizona Administrative Code Distributed Generation Interconnection Requirements, APS's Interconnection Manual, Interconnection Agreement, and APS's Electric Service Requirements Manual.

SPECIAL CASES

1. Switching from a grandfathered L~~l~~egacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the bill credits for export energy will be based on the annual RCP rate as it changes from year to year excepting where 10 or more years are remaining in the solar grandfathering status. In such instances, the Customer will be eligible for a 10-year lock in the purchase rate then in effect at the time of the switch.

2. Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this rate rider, a material increase in capacity means increasing the capacity by 10% or 1 kW-dc, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW-dc, whichever is greater.

3. Transferring Service. If a Customer moves to a site that is currently being served under Rate Rider RCP, they ~~will~~ may continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have a standard Advanced Metering Infrastructure (AMI) meter installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a Customer's interconnection agreement.

4. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is

configured so that the energy generated first supplies ~~its~~ their own electric requirements, and any excess generation (over and above ~~its~~ their own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer Customers who have an Aggregated Peak Load of ~~10~~ 5 MW or more and are served under Rate Schedules E-34, E-35, E32-L, ~~or~~ E-32 TOU L, E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S. ~~An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.~~

Customers must have interval metering, Advanced Metering Infrastructure, or an authorized alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the Customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the Customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of Customer load~~, 100 MW of which will be initially reserved for Customers with single site peak demands of 20 MW or greater and with monthly average load factors above 70%, unless not fully subscribed during the solicitation process~~.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of an application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-X.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this AG-X rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the aggregated actual hourly metered load for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Resource Adequacy: To ensure the reliable operation of the grid, each Generation Service Provider will assure they have acquired sufficient resources to satisfy forecasted future loads and planning reserve margins by meeting the following criteria:

1. Resource ~~s~~Adequacy not purchased from APS must be sourced from a specific generating unit or sourced from a specified aggregation of resources which could be ~~(, and mustinge~~a specified balancing authority area~~)~~.

   ~~Resources must include a specified balancing authority area.~~

2. Resources must be identified in advance as described in the AG-X Program Guidelines.

3. Resource Adequacy is in excess of the host balancing authority area or supplier's existing commitments for reliability planning, and that it is ~~dedicating~~ dedicated to serving APS customer load. The resource must be able to serve APS customer load during reliability events and cannot be curtailed for another entity except in the case of being sourced from a specified aggregation of Balancing Authority resources and the curtailment is pro-rata with native load of sending Balancing Authority Area.

4. The energy being purchased for Resource Adequacy will be delivered to APS at an agreed upon location via firm or high priority transmission as further described in the AG-X Program Guidelines.

5. Resources must include reserves to meet monthly peak load plus a seasonal planning reserve margin as further described in the AG-X Program Guidelines.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, Customers may enroll on a first come first serve basis. After the initial lottery, if necessary, Customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

Eligible Customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor Customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate Customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer must apply for service under this rate rider schedule.

The Company will conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer must select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company must ~~enter into~~enter a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider must provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts~~,~~ and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company will provide transmission, delivery, and network services to the Customer according to normal retail electric service.

The Generation Service Provider must provide resource adequacy for their Customer's load by either purchasing from APS or by demonstrating Resource Adequacy seasonally through the process as described AG-X Program Guidelines.

1. During the first year after the effective date of this Schedule, AG-X Customers must meet Resource Adequacy as follows:

    a. By purchasing Resource Adequacy from APS and paying a transition reserve capacity charge of $6.453 per kW; or

    b. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW.

2. After the first year following the effective date of this Schedule, AG-X customers must meet Resource Adequacy as follows:

    a. By purchasing Resource Adequacy from their Generation Service Provider and paying a reserve capacity charge of $0.000 per kW; or~~.~~

    b. By purchasing Resource Adequacy from APS and paying a reserve capacity charge equal to the unbundled generation demand charge of E-34.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs ~~on a monthly basis~~monthly according to the AG-X ~~p~~Program ~~g~~Guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company will bill the Customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The Customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

~~APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, and APS will not request recovery of any unmitigated costs resulting from AG-X, if any, in its next rate case.~~

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company will serve as the scheduling coordinator. The Generation Service Provider must provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT, which now reflects the terms of the CAISO imbalance charges.

ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in subsection i above, ~~i)~~ GSPs would pay a penalty of $3 per MWh.

iii. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again ~~in a subsequent month,~~ within 12 months from the date of the first notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of the GSP's termination, the Customer will be required to secure a replacement GSP within 60 days, and will be subject to the terms listed in "Default of the ~~third~~ Third ~~p~~Party ~~g~~Generation ~~p~~Provider".

DEFAULT OF THE THIRD--PARTY GENERATION PROVIDER

~~In the event that~~If the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days of such notification. Prior to execution of any new power contract, the Company will provide the required power to the Customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the Company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the Customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customers may return to the Company's Standard Generation Service under their applicable retail rate schedules if: (1) they provide one ~~or more~~ years notice to the Company and are receiving Company provided RA; (2) they provide three years notice to the Company where they are receiving GSP provided RA; or (~~2~~3) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to ~~the~~ Customers under the following conditions. The Company may elect to provide a~~the~~ Customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain ~~1~~ one year notice if the ~~c~~Customer had previously been receiving Company provided RA or three years notice if the ~~c~~Customer had previously been receiving GSP provided RA, at which time the Customer returns to the Company's Standard Generation Service under its~~their~~ applicable retail rate schedule. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the Customer's applicable retail rate schedule will continue to apply except as follows:

1. The ~~-~~generation charges will not apply;

2. Adjustment Schedule PSA-1 will not apply;

3. Adjustment Schedule EIS will not apply; and

4. The applicable proportionate part of any taxes or governmental impositions, which are or may in the future be assessed based on any of the following will be applied to the Customer's bill ~~on the basis of~~:

   a. The Company's gross revenues ~~of the Company and/or~~.

   b. ~~t~~The price or revenue from the electric energy or service sold ~~and/or~~.

   ~~4.~~c. ~~t~~The volume of energy generated or purchased for sale ~~and/or~~or sold hereunder~~, will be applied to the Customer's bill~~.

Schedule AG-X charges determined and billed by the Company include:

1. A monthly administrative management fee of $0.~~00171~~ 00164 per kWh applied to the Customer's billed kWh;

2. A monthly reserve capacity charge ~~of $5.248 per kW~~ applied to 100% of the Customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);

3. Returning Customer charge, where applicable, as described herein;

4. Generation Service Provider Default charge, where applicable, as described herein.

~~These charges and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.~~

Schedule AG-X Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges will be charged at a rate within the minimum and maximum limits as follows:

   a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
   b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The

determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.

c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges will be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with ~~Section~~ section ~~IV~~ iii under ~~imbalance~~ Imbalance ~~services~~Services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to, the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

AG-X customers that aggregated accounts to meet the ~~10~~5 MW minimum load size eligibility requirements may add new accounts not previously on their application if their load falls below the ~~10~~5 MW threshold because of participation in energy efficiency programs.

AG-X customers may grow up to 10% beyond their original allocation in the program.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

AVAILABILITY

This rate schedule is available to all Customers served on Rate Schedules E-32 M, E-32L, E-32 TOU M, E-32 TOU L, E-34, E-35, and E-221.

DESCRIPTION

Critical Peak Pricing (CPP) events are specific hours within the summer months when the Company is expecting extreme temperatures, high energy (kWh) usage, high market energy costs, or is experiencing a major generation or transmission outage. Customers on this rate rider agree to use less energy during these CPP events. Energy charges during CPP events are higher than the remainder of the summer On-Peak hours, but the Customer also receives a discount for all other energy used during the CPP summer months.

CHARGES

The following charge is in addition to the On-Peak charge in the Customer's rate schedule:

Charge for energy use during Critical Peak hours	$0.25000	per kWh

The following discount will apply to all non-Critical Peak hours during CPP Summer months (June through September):

Rate Schedule E-32 M	$ (0.010351)	per kWh
Rate Schedule E-32 L	$ (0.009533)	per kWh
Rate Schedule E-32 TOU M	$ (0.009266)	per kWh
Rate Schedule E-32 TOU L	$ (0.008680)	per kWh
Rate Schedule E-34	$ (0.008519)	per kWh
Rate Schedule E-35	$ (0.007396)	per kWh
Rate Schedule E-221	$ (0.006116)	per kWh

SERVICE DETAILS

1. Eligible Customers must be able to reduce their usage during CPP events by a minimum of 200 kW. Any reduced load must have otherwise been served specifically by APS generation.

2. Eligible Customers must submit a load reduction plan, which must be approved by the Company prior to participation.

3. This rate rider requires the Customer's usage to be measured with an AMI meter.

4. A Customer cannot be on this rate rider and another demand response program offered by the Company. Customers may participate in this rate rider and the Legacy EPR-6 Rate Rider, but any exported generation during a CPP event will not be applied toward hours in another CPP event.

5. Details of a CPP event are as follows:

    a. CPP events will only be scheduled from 3 p.m. to 8 p.m., Monday through Friday in the months of June through September. CPP events will not be scheduled on holidays (Independence Day on July 4th and Labor Day on the first Monday in September).

    b. At least 6 and no more than 18 CPP events may be scheduled in each calendar year, and each event will last for a period of five hours.

    c. Customers will be notified of a CPP event in advance. By 4:00 p.m. the day prior to the event, the Customer will receive a phone message, e-mail, or text message. The Customer is responsible to watch for this message.

    d. Once noticed, a CPP event will not be cancell~~l~~ed.

6. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

RATE RIDER DCFC
GENERAL SERVICE
DIRECT CURRENT FAST CHARGING PILOT

DESCRIPTION

This pilot rate rider provides an upper limit to the monthly billed demand, relative to the Customer's monthly kWh usage and billed days, to facilitate the initial deployment of public, fast-charge, electric vehicle charging stations.

AVAILABILITY

This pilot rate rider is available to Standard Offer retail customer service accounts served under rates E-32 TOU Small, E-32 TOU Medium, and E-32 TOU Large, where electricity is consumed only by public, fast-charge, electric vehicle charging stations that are separately metered from other facilities unless those facilities are incidental to the charging load.

This rider is limited to 500 customer service accounts on a first-come, first-served basis and will sunset after the July 2031 billing period.

Other buildings that are on the same site as the vehicle charging facilities will be separately metered and billed under a retail rate, without this rider.

LOAD FACTOR LIMITS

Monthly billing demands are limited to a kW no higher than that which would result in the applicable load factor limit, based on the customer's kWh usage, and billing days during the month. The monthly load factor limits are:

	Monthly Cycle Bills beginning with Cycle 1 Between	Load Factor Limit
Period One	December 1, 2021 through June 30, 2025	25%
Period Two	July 1, 2025 through June 30, 2028	20%
Period Three	July 1, 2028 through June 30, 2031	15%

The monthly billing demand shall be the lower of:

1. The Billing Demand metered and calculated according to the parent rate schedule, or

2. The Limited Demand which equals:
    a. Period One - (Monthly Billed kWh) / [25%*Days*24 hours]
    b. Period Two - (Monthly Billed kWh) / [20%*Days*24 hours]
    c. Period Three - (Monthly Billed kWh) / [15%*Days*24 hours]

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule, other than those specifically modified here, continue to apply.

2. Qualifying direct current fast chargers have a discharge capacity of 50 kW or greater and are available for use by the general public and not restricted.

RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

AVAILABILITY

This rate rider is available to qualifying residential and non-residential partial requirements Customers with an on-site renewable distributed generation system. Residential Customers with an interconnected on-site solar photovoltaic system are not eligible for this rate rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program and exports energy through the Company's distribution grid. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a Time-of-Use (TOU) rate, the export energy will be netted according to the on-peak and off-peak periods. On-peak export energy will be netted against on-peak energy from the Company and off-peak export energy will be netted against off-peak energy, for all unbundled energy components of the rate that have TOU charges.

PURCHASE RATES

After the December bill, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

BILLING DETAILS

1. All terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for any remaining export energy at the purchase price.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. The generator must be interconnected to the Company's distribution grid;

2. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;

3. For non-residential systems, no system may exceed 125% of connected load for its meter, where connected load is defined as the maximum demand divided by 0.6.

4. For all qualifying residential and non-residential facilities, systems of any size are subject to the requirements found in the Arizona Administrative Code Distributed Generation Interconnection Requirements, APS's Interconnection Manual, Interconnection Agreement, and -APS's Electric Service Requirements Manual.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a Customer interconnection agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

    a. Provides part of the Customer's energy requirements at the site where the system is installed;

    b. Uses renewable resources, as defined by the Arizona Corporation Commission, including a fuel cell with the chemical reaction derived from renewable resources or a combined heat and power (CHP) facility as defined by A.A.C. R14-2-2302, to generate energy; and

c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

5. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

RATE RIDER SCHEDULE GPP
GREEN POWER PARTNERS

This rate rider is available to commercial and industrial customers that desire to purchase renewable power from APS. The customer subscribes to a contracted amount of green power and pays a specified price for the power, in addition to their normal retail rate.

APPLICATION

This Rate Rider Schedule GPP is applicable to APS's ("Company") retail Standard Offer business customers served under large and extra-large general service rates unless otherwise specified in the contract. Customers with extra-small, small and medium accounts may also be eligible provided their accounts have an aggregate non-coincident sum of individual peak loads that exceed 1 MW or 5,000 MWh annually. This rider is not available for service accounts participating in Rate Rider AG-X or any successor rate schedule.

The customer must meet the eligibility requirements for the specific green power offering they choose to enroll in.

GREEN POWER OPTIONS

The amount of green energy available for each option under this rate rider will be determined at the sole discretion of the Company. Specific transactions may involve a transfer or retirement of renewable energy credits ("RECs").

Option A

The customer purchases green power from a new APS resource, or group of resources, that is part of the Company's planned resources and in service after January 1, 2021.

The customer subscribes to a specified amount of green power with a purchase commitment of at least one year. The green power will be priced at the time of the offering, and if applicable, a purchase of the RECs may involve an additional charge. The prices will be specified in the customer contract and may be revised from one resource procurement to the next. In the event RECs are transferred or retired as part of these agreements, such RECs will not be used for compliance to meet the state Renewable Energy Standard ("RES") and any revenue associated with the transfer of RECs will be credited to customers. All contracts will be submitted to the Arizona Corporation Commission ("ACC") for approval.

Option B

The customer purchases green power from a new APS resource, or group of resources, that is part of the Company's planned resources and in service after January 1, 2021.

The customer desires the facility to be located in a designated area or specific parcel. The customer subscribes to a designated amount of green power for a minimum of 20 years.

The pricing for this option will reflect the locational cost differential as determined by the Company. If applicable, a purchase of the RECs may involve an additional charge. The prices will be specified in the customer contract and may be revised from time-to-time. All contracts will be submitted to the ACC for approval.

Option C

The customer purchases green power from a new APS resource, or group of resources, that is not part of the Company's planned resources or seeks to accelerate acquisition of a planned resource. The participating customer will be responsible for all incremental costs, including capital costs.

The customer subscribes to a fixed amount of green power with a purchase commitment for the output of the facility over a mutually agreeable term. The green power will be priced at the time of the offering, and if applicable, a purchase of the RECs may involve an additional charge. The prices will be specified in the customer contract and may be revised from time-to-time. All contracts will be submitted to the ACC for approval.

CHARGES

The customer shall pay a green power price in addition to the customer's full retail rate. All provisions and charges in the customer's rate schedule will continue to apply.

The green power price will be as calculated by the Company, based on resource procurement costs for specified green power facilities and other relevant factors, as discussed above, and the avoided cost of the green power.

The prices will be specified in the customer contract and may be revised from time-to-time.

The green power price for all options will be priced in the range from a minimum of $0.001 per kWh up to a maximum of $0.015 per kWh.

CONTRACT

Customer shall enter into a green power contract with the Company prior to receiving service under this rate rider. The agreement will specify, among other things, the customer accounts receiving green power, the amount of green power, the green power price, the term of the agreement, and the customer credit information.

RATE RIDER GS-EV
GENERAL SERVICE
ELECTRIC VEHICLE RIDER

This page is being included as a placeholder pending the resolution of the APS application for the GS-EV rider in Docket 19-0236.

AVAILABILITY

The Interruptible Rate Program (IRR) rate schedule is available to Customers on Rate Schedules E-34 or E-35.

Customers cannot participate in Rate Rider IRR in conjunction with other demand response programs and rate riders such as Critical Peak Pricing (CPP-GS), Peak Solutions, Power Partners, and other programs and rates that may be offered from time to time.

Participation under this schedule is subject to the availability of required metering and communication equipment compatible with the Customer's applicable retail rate schedule and electrical service configuration and availability of the necessary load data to establish the Baseline Load. The Company will provide any required equipment.

DESCRIPTION

Rate Rider IRR is a demand response program where a Customer has the ability to choose how many hours and days per year the Customer's energy usage can be interrupted during the summer months. The Company's request to lower energy usage is called an event.

The Customer agrees to the amount of load reduction in an executed contract. Customers may enroll in this rider in the months of October through December in any calendar year.

TIME PERIODS

Events may occur June through September, all days of the week including holidays, from 12 noon to 8 p.m.

Customers will choose the maximum number of Events and hours per Event per Program Year from the following options:

Option	Max Hours per Event	Max Number of Events	Max Interruptible Hours
1	4	20	80
2	8	10	80

APS will not call more than one interruption event per day. APS will call at least 2 events per year. The Customer will choose either a 30-minute or 2-hour notice period. The Company will notify the Customer of an event by e-mail, cell phone, land line, text message or pager as chosen by the Customer. The Customer is responsible for receiving notification and acknowledging receipt of that notification to the Company within 15 minutes of receipt.

CREDITS

The Customer will receive a capacity credit and an energy credit for reducing hourly usage during all event hours. The capacity credit will be derived by multiplying the average actual interrupted demand for all events in a calendar year by the Customer by the applicable capacity credit rate. The energy credit will be derived by multiplying the energy reduced for all events in a calendar year by the Customer by the applicable energy credit rate.

The credits will be issued once a year in November through a direct payment or a bill credit, at the Company's option.

The credit rates will be revised from time to time, as approved by the Arizona Corporation Commission, but will not change during the Program Year.

All Customers participating in a five-year agreement will be subject to any revised credit rates for the calendar year, regardless of the number of years remaining on their contract.

1 Year Agreement Credit Rate:

Option	30 Minute Notice		2-Hour Notice	
	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$7.975	$0.09969	$7.178	$0.08972
2	$5.995	$0.07493	$5.395	$0.06745

5 Year Agreement Credit Rate:

Option	30 Minute Notice		2-Hour Notice	
	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$9.882	$0.12353	$8.894	$0.11117
2	$7.428	$0.09285	$6.685	$0.08356

If at least 50% of the data necessary to calculate kW is available, any missing kW values will be estimated using the average of the available hourly data for a specific event. If less than 50% is available, the missing kW values will be estimated using the Customer's agreed level of load reduction in the contract.

SERVICE DETAILS

1. For any Event Year, if the Average Shortfall Demand is greater than 5% and less than or equal to 10% of the Required Interrupted Demand, the Customer will receive 50% of the capacity credit. If the Average Shortfall Demand exceeds 10% of the Required Interrupted Demand, the Customer will not receive a capacity credit. In either case, the Customer will continue to receive 100% of the energy credit. The penalty will not apply to the first Event of the Customer's first Program Year on Schedule IRR.

2. If the Customer terminates participation prior to the contract term in a five-year agreement, the Customer will pay the Company a penalty equal to the relevant Capacity Credit rate times the Required Interrupted Demand from the most recent Event Year (with a minimum of 500 kW) times the number of years remaining on the agreement. The total penalty shall be assessed at the time of termination.

3. If a Customer terminates participation prior to the contract term in a one-year or a five-year agreement, the Customer will not be allowed to participate in the rate for the two subsequent years.

4. All the terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

This rate rider is for retail customers that were awarded hydro power from a federal dam. It explains how APS will deliver the power to the Customer and net it off of their retail bill. This program supports Arizona's effort to take full advantage of the State's allocation of hydro-electric power from Hoover Dam, Parker Davis Dam and Glen Canyon Dam.

APPLICATION

This Rate Schedule PPR Preference Power Rider ("Schedule PPR") is applicable to APS's ("Company") retail Standard Offer customers who receive a firm electric service allocation of preference power from the Western Area Power Administration ("WAPA"), an agency of the U.S. Department of Energy or the Arizona Power Authority ("APA"). Schedule PPR is applicable to all Preference Power allocations awarded from WAPA or APA after January 1, 2007.

Schedule PPR may be used with the following retail rate schedules: E-34, E-35, E32-L, E32-M, E32TOU-L, E32TOU-M and E-221 or successor rate schedules.

All provisions of the Customer's retail rate schedule will apply in addition to Schedule PPR.

Definitions

1. Preference Power Allotment ("Allotment", "Preference Power"): Hydro power, energy and capacity, awarded to the Customer from WAPA as recorded in the Federal Register or from the Arizona Power Authority ("APA"), as specified in Electrical Supply Agreement.

2. Hydro Power: Electricity produced from generators that are run by moving water.

3. Firming Power: In any given month or year the actual amount of Preference Power that the Customer receives may be less than their Allotment. In this case the Customer is allowed to arrange for other power, up to the energy and capacity specified in the Allotment, to make up the difference.

4. Layoff Power: Preference Power purchased from, or sold to, another allottee. Layoff Power purchased from another allottee may be used as Firming Power. Any Layoff Power purchases made above the Customer's Allotment are not eligible for bill crediting under this program.

Preference Power Program

1. APS will schedule all of the Preference Power, including any Firming Power and Layoff Power, according to APS's system requirements and manage any delivery and coordination details. Any Preference Power not scheduled by APS, or not available during the Company's desired time periods, will not be eligible for bill crediting under this program.

2. APS will take delivery of the Preference Power, up to the Customer's Allotment, at a delivery point specified by APS in an Electrical Supply Agreement and transport it to the Customer's business location at no additional charge above the current retail rate for power transmission and delivery. The standard delivery point for Preference Power from the Hoover Dam will be the Mead substation near Boulder City, Nevada.

3. The Customer will designate one retail account, as the primary account to receive the Preference Power. The Customer may also designate a back-up account in the event the load from the designated primary account falls below the Preference Power Allotment in an occasional month. If the Customer's Preference Power Allotment is greater than any single account then up to three accounts may be used.

4. The Customer may change their Preference Power account designations once per calendar year.

5. The amount of Preference Power including any Firming or Layoff Power will be limited to the Customer's annual and seasonal Allotment. However, the Customer may schedule additional Preference Power during the summer season (March – September) and less during the winter (October – February), as long as the annual total does not exceed the Allotment.

6. The amount of the Preference Power credit will also be limited to the kWh on the Customer's monthly retail bill for the designated account(s).

7. Preference Power credits are not eligible for direct access Customers or those on rate rider AG-X.

Bill Credit

The Customer's monthly bill will first be calculated without the Preference Power according to the Customer's standard retail rate schedule.

The Preference Power capacity and energy scheduled for the month will then be credited off of the retail capacity and energy charges for generation service based on the credit rates in this rate rider. The Preference Power energy will also be credited off of the kWh charges in Adjustment Schedule PSA-1, which are revised annually.

The credit rates include the unbundled generation capacity demand charges and energy charges consistent with APS's retail rates for medium, large and extra-large business Customers and adjusted for average system kWh line losses. The capacity demand charges in the retail rates are converted to equivalent energy (kWh) amounts based upon class billing determinants in the most recent rate case.

The credit rates will be revised from time to time to reflect changes in the retail rates as approved by the Arizona Corporation Commission.

The credit rates are based on the size of the capacity Allotment, not the specific retail rate for the designated account(s).

	Preference Power Credit Rates ($/kWh) (excluding credit for schedule PSA-1)	
Preference Power Allotment	Summer (May - October)	Winter (November - April)
1MW and above	$0.06034~~0.04729~~	$0.06034~~0.04729~~
401 kW - 999 kW	$0.07232~~0.05731~~	$0.05428~~0.04287~~
0 kW - 400 kW	$0.07750~~0.06185~~	$0.06032~~0.04846~~

Contract

Customer must enter into an "Electrical Supply Agreement for Customers with Preference Power" with the Company prior to receiving service under Schedule PPR. This agreement will specify, among other things, the Customer accounts receiving Preference Power and the amount of the Preference Power Allotment.

RATE RIDER SD-1
GENERAL SERVICE
SCHOOL DISCOUNT RIDER

AVAILABILITY

This rate rider is available to all public elementary and secondary schools (K through 12) served under rate schedules E-32 XS, E-32 XS D, E-32 S, E-32 M, E-32 L, E-32 TOU XS, E-32 TOU S, E-32 TOU M, E-32 TOU L, GS-Schools M, and GS-Schools L.

DESCRIPTION

This rate rider provides a monthly bill discount for a public elementary and secondary (K-12) school requesting service under this rate rider.

DISCOUNT

The following discount will apply to the Customer's monthly billed kWh:

Discount	$0.002930.00234	per kWh

SERVICE DETAILS

1. The discount will be applied to the monthly billed kWh prior to the application of taxes, regulatory assessment, and franchise fees.

2. This discount is not available to Direct Access Customers or Customers on Rate Rider AG-X.

3. Customers may not receive discounts under both this rider and the E-32 L or E-32 TOU L Aggregation Discount at the same time.

4. All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

AVAILIBILITY

This rate rider is available to eligible public elementary and secondary schools (K through 12) including charter schools, and eligible government customers served under rate schedules E-32 S, E-32 M, E-32 L, E-32TOU S, E-32TOU M, E-32TOU L, GS-SCHOOLS M, GS-SCHOOLS L, E-34, and E-35.

A Customer on this rate rider cannot also be on a Partial Requirements rate rider or rate rider AG-X.

This rate rider was frozen on August 19, 2017. This means no new Customers will be served under this rider after that date, and any Customer that moves to another available rate rider cannot move back to this one. Customers may remain on this rider for up to 20 years from the date an on-site distributed generation system was connected to the Company's distribution grid.

DESCRIPTION

This rate rider provides a 20-year fixed charge for a portion of the Customer's monthly energy usage equal to the energy produced by a Company-owned on-site solar distributed generation system that is directly connected to the Company's distribution grid.

SOLAR ENERGY

Solar Energy, which is used in the calculation of the Solar Charge below, is the expected monthly kWh production from the Company's solar equipment over time. The applicable Solar Energy is calculated by multiplying the kW-DC nameplate generator rating of the system by an average monthly production factor of 90 kWh-AC per kW-DC.

CHARGES

The Customer's monthly bill will be calculated in accordance with the current applicable rate schedule except:

The monthly bill will include a Solar Charge, which is the Solar Energy multiplied by the charges listed below:

Applicable Retail Rate Schedule	Solar Charge	
E-32 S, E-32 M	$0.07665	per kWh
E-32 L	$0.04660	per kWh
E-32TOU S, E-32TOU M, E-32TOU L	$0.05502	per kWh

FROZEN

GS-SCHOOLS M, GS-SCHOOLS L	$0.07571	per kWh
E-34	$0.04236	per kWh
E-35	$0.04128	per kWh

BILLING DETAILS

1. The monthly bill will be based on the Customer's total metered usage net of the Solar Energy, but the netted kWh shall not be less than zero. The netting will be applied as follows:

   a. For Customers on Rate Schedules E-32TOU S, E-32TOU M, E-32TOU L, and E-35:

On-Peak kWh	50.0%
Off-Peak kWh	50.0%

   If the net kWh is less than zero for either the On-Peak or Off-Peak period, the remaining kWh will be netted from the other time period, but the netted amount will not be less than zero.

   b. For Customers on Rate Schedules E-32 S and E-32 M:

First 200 kWh per kW	60.0%
All additional kWh	40.0%

   If the netted kWh is less than zero for either tier, the remaining kWh will be netted against the other kWh tier, but the netted amount will not be less than zero.

   c. For Customers on Rate Schedules GS-SCHOOLS M and GS-SCHOOLS L:

   Solar Energy shall be netted from the On-Peak~~, Shoulder Peak~~ and Off-Peak kWh as follows:

	On-Peak	Off-Peak
Summer Peak (May~~Jun~~ Oct~~Aug~~)	50.0%	50.0%
Winter (Nov-Apr)	30.0%	70.0%

FROZEN

If the net kWh is less than zero in any period, the remaining kWh will be applied first to the On-Peak, ~~then the Shoulder Peak, and~~ then to the Off-Peak period if necessary, but the resulting kWh in any period will not be less than zero.

d. For Customers on Rate Schedules E-32 L and E-34, Solar Energy will be netted from the total monthly kWh, but the resulting kWh will not be less than zero.

2. Any reductions to the Customer's monthly kWh billed under Adjustment Schedule REAC-1 ~~and Adjustment Schedule EIS~~ due to participation in Green Power Rate Riders GPS-1, GPS-2, and GPS-3 will be capped at the Customer's total metered kWh net of the Solar Energy provided in this rider.

3. Solar Energy is netted against the metered kWh from the single service entrance section where the system is installed and will not be netted against metered kWh from any other points of delivery at either the same Customer site or other sites. If a Customer has totalized metering service provided under Service Schedule 4, the Solar Energy will not exceed the metered kWh from the single service entrance section where the solar facility is installed.

FROZEN

AVAILABILITY

This rider rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

This rider rate schedule is applicable to retail Customers who obtain any part of their electric requirements from on-site generation equipment with a continuous nameplate rating of 100 kW or greater for other than emergency purposes, requiring Supplemental and Back-up or Maintenance Power and energy from the Company. Direct Access Customers are not eligible for service under this rate schedule. All provisions of the Customer's applicable retail rate schedule will apply except those specifically modified herein. Total measured demand at the Customer's meter will be used to determine the applicable retail rate schedule.

DEFINITIONS

1. Back-up Contract Demand − The specified demand, in kilowatts, of Back-up Power that the Customer contracts with the Company to supply and which the Company agrees to have available for delivery to the Customer. The Back-up Contract Demand shall be established by agreement between Customer and Company. The level of Back-up Contract Demand shall not exceed the total output capacity of the Customer's generation facilities.

2. Back-up Power − The kW of Back-up Contract Demand supplied by the Company to the Customer. Back-up Power shall be determined for each day of the Billing Period containing on-peak hours. The kW of Back-up Power each day shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Back-up Power during the on-peak hours of the day. The Back-up Power for the Billing Period shall be the sum of the Back-up Power for each day of the Billing Period. For each fifteen-minute period, Back-up Power shall equal the Measured Demand minus the Supplemental Contract Demand but shall not be less than zero nor greater than the Back-up Contract Demand.

3. Billing Period − The period of approximately thirty (30) days intervening between regular successive meter reading dates. There shall be twelve (12) billing periods per year.

4. Excess Power − Excess Power is power supplied by the Company to the Customer in excess of the Total Contract Demand. The kW of Excess Power for the Billing Period shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Excess Power during the Billing Period. For each fifteen-minute period, Excess Power shall equal the Measured Demand minus the Total Contract Demand but shall not be less than zero.

5. Maintenance Power - Electric power and energy made available by the Company to a Customer during the scheduled maintenance periods established in accordance with the provisions of this schedule to replace Back-up Power. Maintenance Power shall not exceed the Back-up Contract Demand.

6. Measured Demand - The fifteen (15) minute Demands (Power) in kilowatts as shown by or computed from the readings of the Power (Demand) meter located at the Company's point of delivery for on-peak and off-peak periods during the Billing Period.

7. Measured Energy - The electric energy in kilowatt-hours as shown by or computed from the readings of the kilowatt-hour meter located at the Company's point of delivery.

8. Supplemental Contract Demand - The specified demand in kilowatts of Supplemental Power that the Customer contracts with the Company to supply and which the Company agrees to have available for delivery to the Customer

9. Supplemental Power – The kW of Supplemental Contract Demand supplied by the Company to the Customer. The kW of Supplemental Power for the Billing Period shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Supplemental Power during the Billing Period. For each fifteen-minute period, Supplemental Power shall equal the Measured Demand but shall not be less than zero nor greater than the Supplemental Contract Demand.

10. Total Contract Demand - The sum of the Supplemental Contract Demand and the Back-up Contract Demand.

DETERMINATION OF SUPPLEMENTAL AND BACKUP CONTRACT DEMAND

The Supplemental Contract and Backup Demand shall be initially established by agreement between the Customer and the Company, and shall be reset annually based on the average daily maximum Measured Demand over the six months, May through October of the most recent year.

MONTHLY RATES

The bill shall be the sum of the amounts computed below, including any applicable adjustments:

A. Basic Service: The Basic Service and Revenue Cycle Service Charges included in the Customer's applicable General Service rate schedule will apply each month.

B. Supplemental Power and Associated Energy: Supplemental Power and Associated Energy will be provided in accordance with the rate levels contained in the Customer's applicable

General Service rate schedule, excluding the monthly Basic Service and Revenue Cycle Service Charges, and also excluding delivery charges associated with Back-up Contract Demand.

C. Delivery Charges: The unbundled delivery charge contained in the Customer's applicable General Service rate schedule multiplied by the amount of Back-up Contract Demand.

D. Back-up Power Charges:

Rate Schedule E-34 Customer - On-Peak:	$ 0.775 ~~0.631~~ per kW Day
Rate Schedule E-32 L Customer - On-Peak:	$ 0.157 ~~0.128~~ per kW Day
During Scheduled Maintenance:	One Half (1/2) the On-Peak Charge
Off Peak:	No Charge

On-Peak Periods:	9 a.m. to 9 p.m., weekdays
Off-Peak Periods:	All other hours

The Power Charge for Back-up Power is billed on a per day basis and is based on the fifteen (15) minute period of the Customer's greatest use of Back-up Power during on-peak hours each on-peak day. For each fifteen-minute period, Back-up Power shall equal the Measured Demand minus the Supplemental Contract Demand but shall not be less than zero nor greater than the Back-up Contract Demand.

E. Excess Power Charges:

Secondary Service:	$ 65.676 ~~53.452~~	per kW
Primary Service:	$ 62.342 ~~50.738~~	per kW
Transmission Service:	$ 45.764 ~~37.246~~	per kW

F. Back-up, Maintenance and Excess Energy: All Back-up, Maintenance, and Excess Energy shall be billed in accordance with the customer's applicable General Service rate schedule.

MAINTENANCE REQUIREMENTS

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per generation unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months, as defined in the Customer's applicable general service rate schedule. Customer shall provide Company with its planned maintenance schedule 90 days in advance of any planned maintenance in order for the Company to coordinate Customer's scheduled maintenance with that of the Company. Upon

review, Company shall either approve Customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

METERING

The Company will install, at the Customer's expense, a bi-directional meter at the point of delivery to the Customer (Supply Meter) and meter(s) at the point(s) of output from each of the Customer's generators (Generator Meter) if required. All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company.

TOTAL CONTRACT DEMAND, SUPPLEMENTAL CONTRACT DEMAND, AND BACK-UP CONTRACT DEMAND

The Customer shall contract for Total Contract Demand. This shall be the sum of the Supplemental Contract Demand and the Back-up Contract Demand. The Customer may elect to increase Total Contract Demand by increasing Supplemental Contract Demand and/or Back-up Contract Demand prospectively at any time, provided there are facilities of adequate capacity, by providing notice to the Company. Any increase in Total Contract Demand shall establish a new Total Contract Demand which shall be in effect for the term of the contract, unless superseded by subsequent increases in Total Contract Demand.

TERMINATION PROVISION

Should Customer cease to operate his generation unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

UNUSUAL UTILITY OPERATING CONDITIONS

If the Company is in need of additional power requirements due to equipment failure or other unusual conditions, the Customer may provide excess generation to Company at Company's request. The Company will pay the Customer for any energy purchased at the per kWh monthly firm purchase rate which is negotiated on a case-by-case basis.

TERMS AND CONDITIONS

Customer must enter into an Agreement for Interconnection and an Electric Supply Agreement which shall establish all details related to interconnection and other required service standards. Qualifying Cogeneration and Small Power Production Facilities (QFs) meeting Public Utility Regulatory Policy Act of 1978 criteria shall be permitted to sell excess power and energy subject to the provisions and rates specified in a Purchase Supply Agreement between Company and Customer. Customers who install facilities that do not meet QF standards will not have the right to sell power and energy to Company under this rate schedule. However, should Customer desire to do so, Customer may seek to enter into a new Service Agreement which would set forth the applicable purchase rates, terms and conditions for interconnection and for the sale of excess power to the Company. Customers cannot combine this rate with any other rate riders.

AVAILABILITY

This rate rider schedule is available to Customers with a Qualifying Renewable Facility capable of supplying all or a portion of its power requirements.

DESCRIPTION

This rate rider describes how the Company will bill Customers with an on-site Qualifying Renewable Facility requiring Supplemental and Standby Power and energy from the Company. This rate rider also describes how the Company will purchase any Excess Generation from that same Customer.

All provisions of the Customer's retail rate schedule will continue to apply except as noted below.

TIME PERIOD

For purposes of this rider the On-Peak and Off-Peak hours are as specified under a Customer's retail parent rate schedule.

The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider. The monthly bill will consist of the following charges, plus adjustments:

1. Supplemental Service:

    a. Supplemental demand and energy will be determined and billed according to the Customer's retail rate schedule.

2. Standby Service Charges:

    a. Standby Demand will be the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter Equipment at the time the Customer's Supply Meter registers the highest 15-minute integrated kW demand during the billing month. For Customers served under a time-of-use rate, Standby Demand will be determined for the applicable on-peak and off-peak periods.

    b. Standby Energy will be the kWh measured on the Generator Meter Equipment during the billing month.

c. The Standby Service charge will be the unbundled delivery demand charge contained in the Customer's retail rate schedule multiplied by the Standby Demand. For Customers served under a time-of-use rate, this amount will be calculated for the applicable on-peak and off-peak periods; plus

d. The unbundled delivery energy charge in the Customer's retail rate schedule (if any) multiplied by the Standby Energy.

e. If the applicable rate schedule does not have unbundled charges, standby service will be based on the demand charge in the Customer's retail rate schedule less the unbundled transmission charge in Rate Schedule E-32 L, the result multiplied by the 15 minute integrated kW measured on the Generator Meter during the Customer's monthly peak demand.

PURCHASE RATES

The Company will record and purchase the Excess Generation from the Customer at the applicable per kWh seasonal non-firm purchase rates provided in Rate Rider Schedule EPR-2.

SERVICE DETAILS

1. Definitions

a) Qualifying Renewable Facility – A facility for the production of electricity that:

i. Is operated by or on behalf of the participating Customer and is located on their premises and;
ii. Provides part or all of the Customer's energy requirement at the site where the system is installed;
iii. Uses renewable resources, as defined by the Arizona Corporation Commission, to generate energy;
iv. Has a nameplate capacity continuous AC service rating of greater than 100 kW and;
v. Is interconnected with and can operate in parallel and in phase with the Company's existing distribution system.

b) Partial Requirements Service - Electric service provided to a Customer that has an interconnected generator, where the generation output first supplies the Customer's electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

c) Non-Firm Power - Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided, and the power can be interrupted by the Customer at any time.

d) Excess Generation - Equals the Customer's generation (kWh) in excess of their load at any point in time as metered by the Company. Excess Generation is computed for on-peak and off-peak billing periods.

e) Firm Power - Electric power which is supplied by the Customer's generator with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources. Firm Power will be determined in accordance with Rate Schedule EPR-2.

f) Generator Meter Equipment – Equipment which measures the demand and energy output of the Customer's generator. For Customers with multiple generators, such equipment will consist of one meter for each generator.

g) Supplemental Service - Demand and energy provided by the Company to the Customer to augment the power and energy provided by Customer's generation facility.

h) Supply Meter – Equipment which measures the demand and energy provided by the Company to the Customer and may also measure the excess generation flowing from the Customer generator back to the Company.

i) Standby Service - Demand and energy provided by the Company to the Customer to backup the power and energy from the Customer's generation facility.

2. Supplemental Service will be provided at three phase at approximately 60 Hertz with a delivery voltage as specified in the Electric Supply Agreement.

3. The Company will install, at the Customer's expense, a bi-directional meter at the point of delivery to the Customer (Supply Meter) and a meter at each point of output from each of the Customer's generators (Generator Meter Equipment). All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company. A bi-directional meter may not be required if the Customer cannot be served through a bi-directional meter, or if the generating capacity of the Qualifying Renewable Facility is less than 20% of the Customer's lowest billing demand over the 12 months prior to seeking enrollment in Schedule E-56R, or as otherwise determined by the Company through available information, or if the Customer agrees that they do not intend to be compensated for any Excess Generation.

4. The Company will not record or purchase Excess Generation for Customers not served with a bi-directional meter.

5. Customers cannot combine this rate with another partial requirements rate.

6. Customer must enter into an Interconnection Agreement with the Company.

RATE RIDER EPR-2
PARTIAL REQUIREMENTS SERVICE FOR QUALIFIED FACILITIES OF 100 kW OR LESS

AVAILABILITY

This rate rider is available to Customers with a qualifying on-site cogeneration or small power production facility (QF) with a generating nameplate capacity of 100 kW-ac or less which is interconnected to the Company's distribution grid. Contracts between APS and QFs larger than 100kW will be consistent with Decision Nos. 52345 and 77512.

DESCRIPTION

This rate rider describes how the Company will bill a Customer with an on-site QF. A partial requirements Customer has on-site generation that serves some of their electrical needs and relies on the Company for additional electrical services. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

TIME PERIODS

The On-Peak and Off-Peak purchase rates below will be applied to the specific On-Peak and Off-Peak hours under a Customer's retail rate. If the Customer's retail rate has a Shoulder-Peak period, these hours will be credited at the On-Peak purchase rate.

The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

PURCHASE RATES

The export energy will be acquired by the Company in exchange for a credit on the Customer's monthly bill, based on the following rates for summer and winter seasons:

	Summer	Winter	
On-Peak Non-Firm Rate	$0.02989	$0.03040	per kWh
Off-Peak Non-Firm Rate	$0.02897	$0.02831	per kWh
On-Peak Firm Rate	$0.04297	$0.03040	per kWh
Off-Peak Firm Rate	$0.03009	$0.02831	per kWh

BILLING DETAILS

All terms and charges in the Customer's rate schedule continue to apply to electric service provided under this rider.

SERVICE DETAILS

1. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the Customer's own generation facilities).

2. Customers cannot combine this rate rider with another partial requirements rate or rate rider.

3. A Qualifying Facility (QF) is a cogeneration or small power production facility which meets the requirements for QFs under 18 CFR, Chapter 1, Part 292, Subpart B of the Federal Energy Regulatory Commission requirements. To qualify for this rate rider, the QF must have a nameplate continuous output power rating of 100 kW or less.

4. Export energy equals the Customer's generation (kWh) in excess of their electricity needs at any point in time as metered by the Company. Export energy is metered and accumulated instantaneously for any part of an hour.

5. Non-Firm Power is electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

6. Firm Power is power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

7. Electric sales to the Company must be single phase or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises).

8. Power sales and services supplied by the Company to the Customer in order to meet its electric requirements will be priced at the Customer's retail rate schedule.

9. Customers served under this rate schedule must have an AMI meter that will register and accumulate the net electrical requirements of the customer. The AMI meter will be provided at no additional cost to the customer.

10. The Company provides service under this rider in accordance with its Interconnection Requirements Manual, which has provisions that may affect the Customer's bill. Special provisions may also be included in a Customer interconnection or purchase agreement.

Demand Side Management Adjustment Charge
Plan of Administration

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1. General Description

This document describes the plan for administering the Demand Side Management Adjustment Charge (DSMAC) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (Commission) in Decision No. 67744, and later revised by the Commission in Decision Nos. 71448, 73183, 74406, 76295, ~~and~~ 78317, 78585 and XXXXX. The DSMAC provides for the recovery of Demand Side Management (DSM) program costs, including energy efficiency (EE) and demand response programs (DR), and ~~energy efficiency~~DSM performance incentives as well as the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of EE savings and distributed generation (DG) determined to have occurred as described herein~~.~~ The lost fixed costs to be recovered include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution. The DSMAC is applied to Standard Offer or Direct Access customer bills as a monthly kilowatt-hour charge (for Residential customers and General Service customers served in accordance with non-demand billed rate schedules), or kilowatt demand charge (for General Service customers served in accordance with demand billed rate schedules), unless the customer's current rate has alternate provisions. The charges will be filed with the Commission annually when APS submits the ~~Energy Efficiency~~DSM Implementation Plan (~~EEIP~~DSMIP) for approval. This will occur ~~June~~ November ~~1~~st ~~30~~th of each year. If approved by the Commission, the charge will be effective ~~each~~ the following year beginning with billing cycle 1 of the ~~March~~ October revenue month and will not be prorated.

Recovery of all applicable program costs and incentives will be allowed for all programs that have been approved by the Commission.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Current Period – The most recent adjustment year.

DG Savings – The amount of MWh sales reduced by DG. Where available, APS will use meter data to calculate DG system savings. Each year, APS will use DG production data to calculate the savings. The calculation of DG Savings will consist of the following by class:

- Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.
- Excluded MWh Production: The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the LFCR portion of the DSMAC adjustor rate calculation as shown in Schedule 9 of the compliance filing list.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The Return on Equity (ROE) authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

EE (or DSM) Programs – Any program approved in APS's DSM I~~i~~mplementation Plan.

EE Savings – The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

- Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.
- Current Period: The EE related sales reductions (MWh). Each year, APS will use MER verified data to report EE savings.
- Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of actual EE Savings achieved by customers on Excluded Rate Schedules.

Excluded Delivery Revenue – 50% of any delivery demand (kW) revenue as determined in Decision No. XXXXX and calculated on Schedules 6 and 7.

Lost Fixed Cost Rate – A rate determined at the conclusion of APS's most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue (LFCR) – The amount of fixed costs not recovered by the utility because of EE and DG during the period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Performance Incentives (PI) - Represents a percentage of the net economic customer benefits (benefits minus costs) from approved EE programs based on a graduated scale -that is capped at a maximum of $/kWh of first-year EE savings achieved.

Program Costs (PC) - Allowable expenses include, but are not limited to: program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement DSM programs (EE and DR) that are approved by the Commission in the DSMIP. For those DSM programs that may generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Transition Balance – The Lost Fixed Cost Revenue balance as calculated in compliance during that period per Decision No. 73183 and modified in Decision No. 74202.

True-up (TU) – A reconciling of authorized PC and LFCR amounts from the previous approved Plan.

~~2.~~3.Rate Schedule Applicability

The DSMAC shall be applied monthly to every retail Standard Offer or Direct Access service, unless exempted by Commission order.

4. ~~Allowable Costs~~Performance Incentive~~:~~

~~The types of allowable costs are as follows:~~

~~A. Program Costs (PC) – Allowable expenses include, but are not limited to: Program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement cost-effective DSM programs (energy efficiency and demand response) that are approved by the Commission in the EEIP. For those DSM programs that generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.~~

~~B.~~ Performance Incentives (PI) - Represents a percentage of the net economic benefits (benefits minus costs) from approved ~~energy efficiency~~EE ~~programs~~ and DR programs based on a graduated scale that is capped at a maximum $/kWh of first-year savings achieved. ~~percentage of EE and DR PC.~~

Achievement Relative to Annual Goal Approved in APS's DSM~~Energy Efficiency~~ Implementation Plan	Performance Incentive as % of Energy Efficiency and Demand Response Net Benefits	Performance Incentive Cap*
< 85%	0%	Performance Incentive Will Not Exceed $0.0125/kWh Saved
85% to 95%	6%	
96% to 105%	7%	
> 105%	8%	

*The PI cap is based on ~~applies to~~ the annualized incremental first year EE~~energy~~ savings generated plus the equivalent kWh of DR kW savings achieved~~.~~

~~3. Determination of True Up:~~

~~The actual allowable cost recovered for approved DSM programs will be compared to the actual revenues received by the Company through the DSMAC. The True-Up (TU) will be based on the amount in the TU balancing account. This balance will include past period PC, PI and DSMAC revenue collection accruals as of April 30th of the filing year.~~

~~In the event that PC or PI are more or less than DSMAC revenues collected as of the last billing cycle of February, the over or under collection will be subtracted from or added to the DSMAC calculation in the subsequent period. Any over collection will accrue interest charges. Under collections will not accrue interest.~~

~~Illustrative Table of Events~~

~~Date~~	~~Included Items~~
~~7/15/2009~~ ~~DSMAC includes:~~ ~~-~~ ~~-~~	~~File 2010 EEIP with 2010 DSMAC~~ ~~2010 forecast of PC and PI~~ ~~2009 forecast of PC and PI~~ ~~TU balancing account as of the last billing cycle of February~~
~~3/1/2010~~	~~DSMAC start from 2010 EEIP~~
~~6/1/2010~~ ~~DSMAC includes:~~ ~~-~~	~~File 2011 EEIP with 2011 DSMAC~~ ~~2011 forecast of PC and PI~~ ~~TU balancing account as of the last billing cycle of February~~

~~3/1/2011~~	~~DSMAC start from 2011 EEIP~~
~~6/1/2011~~ ~~DSMAC includes:~~ -	~~File 2012 EEIP with 2012 DSMAC~~ ~~2012 forecast of PC and PI~~ ~~TU balancing account as of the last billing cycle of February~~

~~4.~~5. Determination of the Adjustor Charge

By ~~June 1st~~ November 30th of each year, APS will file a revised DSMAC with supporting documentation in the ~~EEIP~~DSMIP. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods.

The DSMAC calculation will be for purposes of recovering PC, ~~and~~ PI, LFCR under the DSM Program and will be developed based on the following formula:

$$DSMAC = \frac{PC + PI + LFCR + TU + I}{Sales}$$

Where:

PC = Program Costs as defined in section ~~3.~~2 forecast for the ~~upcoming~~ plan year.

PI = Performance Incentives as defined in section ~~3.~~2 forecast for the ~~upcoming~~ plan year.

LFCR = Lost fixed cost recovery as defined in section 2.

TU = Any "true-up" balance ~~as defined in section 4~~.

I = Interest associated on any over recovery of DSMAC costs for the prior period. The interest rate is based on the one-year Nominal Treasury Maturities rate from the Federal Reserve H-15 or its successor publication. The interest rate shall be adjusted annually on the first business day of the calendar year.

Sales = Forecast energy (kWh) sales under applicable electric rate schedules during the Adjustor Period in which this adjustor will be effective.

Adjustor Period = The 12-month period beginning with the first billing cycle during March of the current year and ending with the last billing cycle of February of the next year.

The DSMAC for General Service customers that are billed on demand will be calculated as a per kW charge. The DSMAC for General Service customers that are not billed on demand will be calculated as a per kWh charge. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSMAC.

For residential billing purposes, the DSMAC and the Renewable Energy Adjustment Charge (REAC) are combined and will appear on customer bills as the "Environmental Benefits Surcharge." For general service and other non-residential customer billing, the Company may, but is not required to, provide for such combined billing of the REAC and DSMAC. In any event, each adjustor will be kept separate in the Company's books, records, and reports to the Commission.

a. In the event that PC or LFCR are more or less than DSMAC revenues collected as of the last available period prior to filing, the over or under collection will be included in the TU balancing account. Any over collection will earn interest ~~charges~~. Under collections will not accrue interest.
b. LFCR Annual Incremental Cap will be subject to an annual 1% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR calculated increase exceeds 1% of Applicable Company Revenues, any amount above the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance
~~a.~~c. Earnings Test - –Any requested increase in the Schedule DSMAC adjustment mechanism related to LFCR will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold. If the results of the Earnings Test are higher than the Earnings Test Threshold, the Lost Fixed Cost Revenue recovered through Schedule DSMAC will be limited to the amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule DSMAC in a future year. The results of the Earning Test will only affect recovery with respect to LFCR and not affect any recovery associated with EE or DSM Programs.

6. Compliance Reports

APS will provide comprehensive Compliance Reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

Schedule 1: DSMAC Annual Adjustment
Schedule 2: LFCR Annual Incremental Cap Calculation
Schedule 3: LFCR Calculation
Schedule 4: LFCR Historical Transition
Schedule 5: LFCR Test Year Rate Calculation
Schedule 6: Distribution Revenue Calculation – General Service
Schedule 7: Distribution Revenue Calculation – Residential
Schedule 8: Annual DG Installation Report

Schedule 9: Annual Earnings Test
Schedule 10: Capital Structure

7. Review Process

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Section 5. APS will file an updated adjustor charge each year with its ~~EEIP~~ DSMIP on ~~June~~ November ~~1st~~30th. If approved by the Commission, changes in the DSMAC will go into effect on the first billing cycle of ~~March~~ October of the following year~~in the Adjustor Period~~.

~~Environmental Improvement Surcharge~~
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~~1. General Description~~

~~This document describes the plan for administering the Environmental Improvement Surcharge (EIS) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on November 9, 2021 in Decision No. 78317. The EIS provides for the recovery of the capital carrying costs effect of actual environmental investments made by APS and not already recovered in base rates approved in Decision No. 78317or recovered through another Commission approved adjustment. The EIS will be calculated annually based on the EIS Qualified Investments closed to plant in service during the preceding calendar year.~~

~~2. Definitions~~

~~Annual EIS Adjustment~~ ~~The Annual EIS Adjustment represents the EIS Capital Carrying Costs on the Qualified Net Plant to be recovered in the subsequent 12 month period and is assessed to customer bills via the EIS $/kWh rate.~~

~~EIS Capital Carrying Costs~~ ~~EIS Capital Carrying Costs consists of (1) Return on the Qualified Net Plant calculated based on the Company's Weighted Average Cost of Capital (WACC) approved by the Commission in Decision No. 78317 plus a return on the fair value increment (if any) for the Qualified Net Plant; (2) depreciation expense; (3) income taxes; (4) property taxes and (5) associated operations and maintenance expenses (O&M).~~

~~EIS Qualified Investments~~ ~~Investments in Qualified Environmental Improvement Projects. Each EIS Qualified Investment must: (1) be classified in one or more of the FERC plant accounts as listed in Section 3 of this document, or any other successor FERC account, upon going into service and (2) be tracked by a specific project number.~~

~~Fair Value Increment~~ ~~For purposes of the EIS, the difference between the Fair Value of the EIS Qualified Investments and Qualified Net Plant shall be deemed to be zero.~~

~~Qualified Environmental Improvement Projects – Projects designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. These standards and criteria for water, waste and air include but are not limited to limits for carbon dioxide (CO2), sulfur oxide (SOx), nitrogen oxide (NOx), particulate matter (PM), volatile organic compounds (VOC), and toxics such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts.~~

~~Qualified Net Plant – The Qualified Net Plant consists of the EIS Qualified Investments and their associated accumulated depreciation, accumulated deferred income taxes, tax credits and, in the event of federal corporate tax reform, any related unamortized excess deferred taxes, where applicable.~~

~~Total kWh Sales – The total prior calendar year energy (kWh) sales served under applicable ACC jurisdictional electric rate schedules, except Rate Schedules E-36 XL and AG-X as reported in the Company's FERC Form No. 1.~~

~~3. Qualified FERC Accounts~~

~~1. Steam Production~~

- ~~FERC Account 310 – Land and Land Rights~~
- ~~FERC Account 311 – Structures and Improvements~~
- ~~FERC Account 312 – Boiler Plant Equipment~~
- ~~FERC Account 313 – Engines and Engine Driven Generators~~
- ~~FERC Account 314 – Turbogenerator Units~~
- ~~FERC Account 315 – Accessory Electric Equipment~~
- ~~FERC Account 316 – Miscellaneous Power Plant Equipment~~

~~2. Nuclear Production~~

- ~~FERC Account 320 – Land and Land Rights~~
- ~~FERC Account 321 – Structures and Improvements~~
- ~~FERC Account 322 – Reactor Plant Equipment~~
- ~~FERC Account 323 – Turbogenerator Units~~
- ~~FERC Account 324 – Accessory Electric Equipment~~
- ~~FERC Account 325 – Miscellaneous Power Plant Equipment~~

~~3. Other Production~~

- ~~FERC Account 340 – Land and Land Rights~~
- ~~FERC Account 341 – Structures and Improvements~~
- ~~FERC Account 342 – Fuel Holders, Products, and Accessories~~
- ~~FERC Account 343 – Prime Movers~~
- ~~FERC Account 344 – Generators~~
- ~~FERC Account 345 – Accessory Electric Equipment~~
- ~~FERC Account 346 – Miscellaneous Power Plant Equipment~~

~~Please note this list may expand to include other accounts approved by the ACC in the future.~~

~~4. Calculation of Annual EIS Adjustment~~

~~The Annual EIS Adjustment is calculated utilizing the accumulation of Qualified Net Plant and calculated EIS Capital Carrying Costs, as defined above and is applied to applicable customers' total bill via a $/kWh rate over the 12 month period beginning in April of the year following the filing described in Section 6 below. The EIS $/kWh rate is calculated by dividing the Annual EIS Adjustment by Total kWh Sales as determined in Schedule 3 of the filing. The EIS rate will not exceed $0.00050 per kWh.~~

~~5. EIS Balancing Account~~

~~APS will maintain accounting records that accumulate the difference between the actual allowable Annual EIS Adjustment as compared to the actual revenues received by the Company through the EIS surcharge during the recovery period (April through March). The difference will be recorded to the EIS Balancing Account each month and will be provided annually in Schedule 3 of the filing. In the event that Annual EIS Adjustments are more or less than the revenues collected as of the last billing cycle of March, the over or under collection will be subtracted from or added to the EIS calculation in the subsequent period subject to the overall cap of $0.00050 per kWh.~~

~~6. Filing and Procedural Deadlines~~

~~EIS Qualified Projects and the Annual EIS Adjustment calculation will be submitted by the Company to the ACC in the form of Schedules 1 through 3 as attached to this document and described in Section 7 *Compliance Reports*. APS will file the calculated EIS $/kWh rate including all supporting data, with the Commission for the previous year on or before February 1st.~~

~~The Commission Staff and interested parties shall have the opportunity to review the EIS filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted or Staff has filed an objection by April 1st, the new EIS $/kWh rate proposed by APS will go into effect with the first billing cycle in April (without proration) and will remain in effect for the following 12 month period.~~

~~7. Compliance Reports~~

~~APS will provide an annual report to Staff and the Residential Utility Consumer Office detailing all calculations related to the EIS $/kWh rate. The reports will include the following Schedules 1 through 3 as attached to this document:~~

~~Schedule 1: Qualified Investments for EIS Electric Plant in Service~~
~~Schedule 2: Annual EIS Adjustment Calculation~~
~~Schedule 3: Current Year EIS Cap Calculation and Adjustment~~

The EIS and this POA is cancelled as of XXXX as ordered in Decision No. XXXX.

The LFCR and this POA is cancelled as of XXXX as ordered in Decisions No. XXXX.~~Lost Fixed Cost Recovery Plan of Administration~~

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~~1. General Description~~

~~This document describes the plan of administration for the Lost Fixed Cost Recovery (LFCR) mechanism approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on August 18, 2017 in Decision No. 76295. The LFCR mechanism provides for the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of energy efficiency (EE) savings and distributed generation (DG) determined to have occurred. Costs to be recovered through the LFCR include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution.~~

~~2. Definitions~~

~~Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.~~

~~Current Period – The most recent adjustment year.~~

~~DG Savings – The amount of MWh sales reduced by DG. Where available, APS will use meter data to calculate DG system savings. Each year, APS will use actual data from January through September and forecast data for the remainder of the calendar year (October through December) to calculate the savings. The calculation of DG Savings will consist of the following by class:~~

~~a. Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.~~

~~b. Excluded MWh Production: The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.~~

c. True Up Prior Period: The reconciliation of APS's forecast data of DG sales reductions for the three months in the Prior Period to verified DG sales reductions in the Prior Period.

EE Programs – Any program approved in APS's annual implementation plan.

EE Savings – The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

a. Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.

b. Current Period: The annual EE related sales reductions (MWh). Each year, APS will use actual pre MER verified data through November and forecast data for December to calculate annual savings.

c. Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules.

d. True Up Prior Period: The reconciliation of APS's forecast data of annual EE sales reductions for the Prior Period to the MER verified EE sales reductions in the Prior Period.

Excluded Delivery Revenue – 50% of any delivery demand (kW) revenue as determined in Decision No. 76295 and calculated on Schedules 6 and 7.

Excluded Rate Schedules – The LFCR mechanism will not apply to large general service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35, XHLF and E-36 XL, or to unmetered General Service customers under E-30 and lighting schedules, Contract 12.

LFCR Adjustment – Total Lost Fixed Cost Revenue as calculated on Schedule 2, divided by forecast retail kWh sales for the proposed adjustor period. For customers on a demand rate the adjustment will be applied as a kW charge. For customers on an energy only rate the adjustment will be applied as kWh charge. This adjustment will be applied to all customer bills, with the exception of those customers on Excluded Rate Schedules, or if the customer's current rate has alternate provisions.

Lost Fixed Cost Rate – A rate determined at the conclusion of APS's most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE and DG during the calendar year. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Prior Period – The 12 months preceding the Current Period.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Transition Balance – The Lost Fixed Cost Revenue balance as calculated in compliance with the LFCR Plan of Administration applicable during that time period per Decision No. 73183 and modified in Decision No. 74202.

3. LFCR Annual Incremental Cap

The LFCR Adjustment will be subject to an annual 1% year over year cap based on Applicable Company Revenues. If the annual LFCR Adjustment results in a surcharge and the annual incremental increase exceeds 1% of Applicable Company Revenues, any amount in excess of the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one year Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance.

4. Historical Transition

Upon implementation of the revised LFCR Plan of Administration in Decision No. 76295, the Transition balance will be calculated on Schedule 4 (LFCR Historical Transition) and reported on Schedule 2 (LFCR Annual Incremental Cap Calculation).

5. Filing and Procedural Deadlines

APS will file the calculated LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by February 15th. The new LFCR Adjustment will not go into effect until approved by the Commission. If approved, the new rate will take effect with the first billing cycle in May, unless otherwise specified by the Commission.

6. Compliance Reports

APS will provide comprehensive Compliance Reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1: LFCR Annual Adjustment
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Historical Transition
- Schedule 5: LFCR Test Year Rate Calculation
- Schedule 6: Distribution Revenue Calculation – General Service

- ~~Schedule 7: Distribution Revenue Calculation – Residential~~
- ~~Schedule 8 Annual DG Installation Report~~

~~Schedules 1 through 8, attached hereto, will be submitted with APS's annual compliance filing.~~

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism (~~"~~PSA~~"~~) approved for Arizona Public Service Company (APS) by the Commission on June 28, 2007 in Decision No. 69663, and subsequently amended by the Commission in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), 76295 (August 18, 2017)~~,~~ ~~and~~ 78317(November 9, 2021), and XXXXX (Date TBD). The PSA provides for the recovery of fuel and purchased power costs and other production-related variable costs to the extent that those costs deviate from the amount recovered through APS's Base PSA Cost ($0.~~031451~~ 038321 per kWh) authorized in Decision No. ~~78317~~XXXXX, on ~~November 9, 2021~~TBD.

Non-fuel production costs included in the PSA relate to environmental chemical expenses, which vary directly with power plant production. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The PSA allows for the refund or recovery of said costs that deviate from the base cost amount of $0.000500 per kWh[1].

In addition, the PSA allows for the refund or recovery of the net margins from sales of emission allowances to the extent the actual sales margins deviate from the base cost amount of ($0.000001) per kWh,[2] and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.

APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur California's carbon emission allowance costs when doing so is not an economical choice for APS's Arizona ratepayers.

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and environmental chemical costs for fossil fuel production, and

[1] $0.000500 per kWh is the result of the following: (2015 chemical costs of $13,527,111 / 2015 test year native load sales of 27,030,686 MWh) / 1000.
[2]($0.000001) per kWh is the result of the following: (2015 net gains from sales of SO_2 allowances of $25,181 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

margins on the sales of emission allowances ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year absent express approval of the Commission. This PSA also provides a mechanism for mid-year rate adjustment by either the Commission or the Company (only if overcollection occurs) in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year's[3] PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual PSA Costs (fuel, purchased power and other allowable costs) and the recovery of those same cost elements through the combination of base rates and the Forward Component, and which provides for their recovery or refund during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek mid-year changes in the PSA Rate in cases where variances between the anticipated recovery of fuel and purchased power and other allowable costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery/refund, should the Commission deem such an adjustment to be appropriate or if the Company requests to make such a refund of an overcollection.
    b. The tracking of balances resulting from the application of the Transition Components in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before November 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before November 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

[3] Each February 1 through January 31 period shall constitute a PSA Year.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS's over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e., February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual November 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the current PSA Year). The APS filing shall use these balances to calculate the Historical Component for the coming PSA Year[4].

The November 30 filing's use of estimated balances for November through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1.

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any approved mid-year changes to the PSA rate. APS or Staff may request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection

[4] For example, the November 30, 2008 filing would include actual balances for February through October of 2008 and estimated balances for November 2008 through January 2009.

of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component. The Commission on its own motion may also change the PSA rate as described above.

Notwithstanding the preceding paragraph, APS may at any time during the PSA Year request to reduce the PSA through the Transition Component, which shall be deemed approved and become effective beginning with the first billing cycle of the month following the filing of such a request, provided APS files the request within the first 15 days of a month and Staff does not file opposition to the request.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before November 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year.

3. Calculation of the PSA Rate

The PSA Rate is the sum of the three components; *i.e.*, Forward Component, Historical Component and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA Rate by February 1, the proposed PSA Rate shall go into effect. However, the PSA Rate may not change from the prior year's PSA Rate by more than plus or minus $0.004 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA Rate shall be applicable to APS's retail electric rate schedules (with the exception of E-36 XL, AG-X, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA Rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. November 30 Filing

APS shall file the PSA Rate with all Component calculations for the PSA Year beginning on the next February 1, including all supporting data, with the Commission on or before November 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward

Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

b. Additional Filings

APS shall also file with the Commission any additional information that Staff determines it requires to verify the component calculations, account balances and any other matter pertinent to the PSA.

c. Review Process

The Commission Staff and interested parties shall have an opportunity to review the November 30 forecast, balances and supporting data on which the calculations of the three PSA components have been based. Any objections to the November 30 calculations shall be filed within 60 days of the APS filing. Before Storage Product Costs may be calculated in the PSA, APS will first seek approval. APS will request this approval by filing the third-party storage contract with the Commission at least 90 days before the contract becomes effective. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power and other allowable costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA year will be credited an amount equal to interest at a rate equal to the Company's authorized Return on Equity ("ROE") or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

Base Chemical Costs – An amount generally expressed as a rate per kWh, which reflects the non-fuel production costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The Base Chemical Costs are set at $0.000744~~500~~ per kWh effective on ~~December 1, 2021~~TBD.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. ~~78317~~ XXXXX set the base cost at $0.~~031451~~ 038321 per kWh effective on ~~December 1, 2021~~TBD.

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on ~~December 1, 2021~~TBD.

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power as defined above, the Base Chemical Costs, and the Base Net Margins on the Sale of Emission Allowances.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS's base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS's over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue, plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest at year end. The balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mandated Carbon Emission Allowance Costs – The costs incurred in purchasing allowances to meet legal requirements, beginning in 2013, that electricity from resources which emit carbon must be accompanied by carbon emission allowances equal to the amount of carbon emitted in generating the electricity (recorded in FERC Account 509 – Allowances).

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load refers to the energy needed for customer load in the balancing authority area for which APS has a generation service obligation.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

PSA - The Power Supply Adjustment mechanism approved by the Commission.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus costs for environmental chemicals used in power production at fossil and nuclear production sites, approved storage product costs and the Net Margins on the Sales of Emission Allowances.

PSA Year - A consecutive 12-month period generally beginning each February 1.

~~Rate Schedule AG-X - Alternative Generation Rate Schedule approved by the Commission in Decision No. 76295. Resale of capacity and energy displaced by Rate Schedule AG-X shall be excluded from the PSA at a flat amount of $1,250,000 a month. The portion of capacity and energy sales margins that is not the result of displacement from Rate Schedule AG-X will continue to be a credit to the PSA. As authorized in Decision No. 78317, the portion of capacity and energy sales margins displaced by AG-X that grows beyond the original allocation of 200 MW will proportionately increase the $1,250,000 per month exclusion.~~

Storage Product Costs - All costs associated with third-party storage facilities, including rent, capacity, and lease payments for electricity storage facilities (e.g., batteries) that APS utilizes in the dispatch of generated or purchased electricity.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36 XL, AG-X, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. 78317.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS's electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration

Schedule 1	PSA Rate Calculation
Schedule 2	PSA Forward Component Rate Calculation
Schedule 3	PSA Year Forward Component Tracking Account
Schedule 4	PSA Historical Component Rate Calculation
Schedule 5	Historical Component Tracking Account
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account

8. Compliance Reports

APS shall provide monthly reports to Staff and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in APS's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs

b. Margins on the sale of excess emission allowances
c. Environmental chemical costs for fossil generation
d. Customer sales in both MWh and thousands of dollars by customer class
e. Number of customers by customer class
f. A detailed listing of all items excluded from the PSA calculations
g. A detailed listing of any adjustments to the adjustor reports
h. Total off-system sales revenues
i. System losses in MW and MWh
j. Monthly maximum retail demand in MW

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively
2. Average heat rate, both monthly and 12-month average
3. Equivalent forced-outage factor, both monthly and 12-month average
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description
5. Total fuel costs per month
6. The fuel cost per kWh per month

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh
2. The demand purchased in MW to the extent specified in the contract
3. The total cost for demand to the extent specified in the contract
4. The total cost of energy

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer
2. Details on negative off-system sales margins

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm or per MCF, total cost, supply basin and volume by contract

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated over/under-collected amounts
2. A summary of unplanned outage costs by resource type
3. A summary of the net margins on the sale of emission allowances

4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, costs for specified environmental chemicals that vary with power generated at fossil power plants, storage product costs, and the net margins on the sale of emission allowances and Mandated Carbon Emission Allowance Costs will also be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission (FERC) accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- 509 Allowances[6]

Additionally, broker fees recorded in FERC account 557 up to the amount included in the Base Fuel Cost, costs for environmental chemicals used in power production in FERC accounts 502 and 549, and the FERC account where applicable Storage Product Costs will be recorded are allowable accounts.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 (November 18, 2003) provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost

[6] Or any successor FERC account used to record the costs of purchasing carbon emission allowances.

differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 XL and AG-X customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs and kWh usage are excluded from the PSA.

Returning Customer Direct Access Charge
Plan of Administration

General Description

Section 2.6 of the May 17, 1999 Settlement Agreement ("Agreement") in Docket No. E-01345A-98-0473 allows Arizona Public Service Company ("APS") to recover the reasonable and prudent costs associated with compliance and implementation of the Electric Competition Rules beginning July 1, 2004. The Arizona Corporation Commission ("Commission") approved the collection of these costs in Decision No. 67744, Docket No. E-01345A-03-0437. Section 2.6(2) of the Agreement provides the opportunity to recover the costs of providing Standard Offer service to customers who have left an APS Standard Offer service or special contract rate for a competitive generation supplier and are returning to Standard Offer service. Customers that have been Direct Access customers since the origination of their APS service that request Standard Offer service are considered to be returning customers.

The Company may assign any of the above costs directly to the customer(s) who caused them via a Returning Customer Direct Access Charge ("RCDAC"). This will only be done when a customer, or an aggregated group of customers, with a monthly demand of three MW or greater returns to Standard Offer service and APS did not include their load in planned resource acquisitions. If APS is provided one year's advance notice of the customer's intent to return to Standard Offer service then they will not be assessed a RCDAC. APS may create a RCDAC in each individual case and require the customer(s) to enter into a service agreement that specifies the charge, its duration, and how it will be applied and collected. In situations where an aggregated group of customers wish to return, each customer from the group will be charged the same rate for the same duration and an agreement will be required from each customer.

Returning Customer Direct Access Charge

The RCDAC will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning customer(s). The costs associated with serving customers that are required to enter into RCDAC agreements will be kept separate from the retail power supply costs subject to recovery through the Power Supply Adjustment. The types of costs that will be used to develop the RCDAC are Incremental Power Supply, Transmission, Ancillary Services and Metering costs. These terms are defined as follows:

Incremental Power Supply - The costs of generation or purchased power supplied to the customer that is over the base rate power supply cost for their applicable rate schedule.

Transmission – The costs of delivering power across a utility system or to other utility systems.

Ancillary Service – The costs of services necessary to support the transmission of energy from the resources to the loads while maintaining reliable operation of the transmission provider's transmission system.

Metering – The costs of measuring the power used by the customer.

These costs will be amortized over an appropriate period to allow their timely recovery. In no event, however, will the RCDAC last longer than 12 months for any individual customer.

Resource Comparison Proxy
Plan of Administration

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1. General Description

This document describes the plan for administering the Resource Comparison Proxy purchase rate (RCP) approved for Arizona Public Service Company (APS or Company) in Arizona Corporation Commission (Commission) Decision No. 75859 (January 3, 2017), as modified by Decision No. 75932 (January 13, 2017) and implemented in Decision No. 76295 (August 18, 2017) and Decision No. 78317 (November 9, 2021) and Decision No. XXXXX (TBD). The RCP is the price at which the Company purchases Exported Energy from residential Customers with qualified on-site solar distributed generation facilities. This price is provided in Rate Rider RCP.

The RCP is a proxy for the avoided cost of providing electrical service that results when a distributed generator exports power to the grid. The RCP is calculated using: (i) a rolling historical five-year weighted average cost of grid-scale solar photovoltaic facilities that the Company owns or has rights to through a solar photovoltaic Purchased Power Agreement (PPA); and (ii) applicable Avoided Transmission Capacity Cost, Avoided Distribution Capacity Cost, and Line Losses.

2. Customer Billing

The Company will provide the Customer a monthly bill credit for the Export Energy based on the applicable RCP.

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; if the outstanding credits exceed $25 a check will automatically be issued; otherwise the bill credits will carry forward to the following year.

3. Resource Comparison Proxy Purchase Rate

The RCP will be determined as follows:

- An RCP will be determined for each tranche of new DG Customers, effective September 1 each year or as determined by the Commission, without proration. The RCP may not be reduced by more than 10% each year.

- Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before September 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

- Each Customer's initial RCP will be applicable for 10 years from the time of their interconnection.

- After each Customer's initial 10-year period the bill credit will be based on the purchase rate in effect at that time, and will change from year to year.

4. Definitions

Avoided Cost. In the context of this Plan of Administration, the additional cost APS would incur to acquire electric energy to serve its customers if electricity was not available from on-site distributed generation sources.

Avoided Distribution Capacity Cost. In the context of this Plan of Administration, the net cost of distribution grid equipment and facilities necessary to distribute electricity to APS customers if electricity from on-site distributed generation sources was not available.

Avoided Transmission Capacity Cost. In the context of this Plan of Administration, the additional cost of transmission grid equipment and facilities necessary to transmit electricity to APS customers if electricity from on-site distributed generation sources was not available.

Base Year. For the initial RCP calculation (effective September 1, 2017), the Company's most recent test year, calendar year ending December 31, 2015. Each subsequent annual calculation will use the immediately preceding calendar year as the Base Year. As an example, the RCP that will become effective with the first billing cycle of September 2018 will be calculated with the calendar year ending December 31, 2017 as the Base Year.

Customer(s). For purposes of this Plan of Administration, an APS Customer taking service under a Residential rate schedule.

Export(ed) Energy. Energy generated by an on-site interconnected solar photovoltaic distributed generation source that is greater than the Customer's electric load at any single point in time and flows into the Company's distribution grid.

Levelized Cost. For purposes of this Plan of Administration, the net present value of the overall cost of building and operating a grid-scale solar photovoltaic generating plant, or the net present value of the overall cost to APS of an executed solar photovoltaic PPA, over the economic life of the asset and converted to equal annual amounts.

Line Losses. Electric energy lost as it is transmitted from a supply source (i.e., an electric generation plant) to a delivery point (i.e., the Customer's residence or place of business).

Partial Requirements Service. Electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

Production Tax Credit. The income tax credit available in the State of Arizona for taxpayers that own a qualified renewable energy generator as defined in A.R.S. §43-1083.02 and §43-1164.03 that produces energy after December 31, 2010 and before January 1, 2021. The amount of Production Tax Credit available is limited by facility and by calendar year.

Revenue Requirement. For purposes of this Plan of Administration, the amount of revenue calculated to be recovered in rates for the APS-owned grid-scale solar facilities included in the RCP calculation. Revenue Requirement expenses include depreciation expense, income taxes, property taxes, deferred taxes and tax credits where appropriate, associated operation and maintenance expense, and an approved debt and equity return.

5. System Eligibility

A distributed generation facility must meet all of the following qualifications to be eligible for the RCP:

- Electricity must be generated using solar photovoltaic panels;
- The facility must be interconnected to the Company's distribution grid; and

- The generator must be on-site, installed behind the billing meter, and must serve the Customer's load.

Systems of any size are subject to the requirements found in the Arizona Administrative Code Distributed Generation Interconnection Requirements, APS's Interconnection Manual, Interconnection Agreement, and APS's Electric Service Requirements Manual.

SPECIAL CASES

Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the bill credits for export energy will be based on the annual RCP rate as it changes from year to year excepting where 10 or more years are remaining in the solar grandfathering status. In such instances, the customer will be eligible for a 10-year lock in the purchase rate in effect at the time of the switch.

Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this Plan of Administration, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.

Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

6. Calculation of Resource Comparison Proxy Purchase Rate

The RCP is calculated by developing a historical rolling five-year weighted average cost per kWh for all grid-scale renewable solar photovoltaic generating systems used by APS to serve its customers, both APS-owned facilities and facilities from which APS purchases power through an executed PPA. The calculation methodology is as follows:

The first RCP effective on September 1, 2017 is $0.12900/kWh, using 2015 as the Base Year inclusive of adjustments as provided for in Decision No. 75859. Subsequent RCPs derived from following the calculations in Steps 1 through 8 below will then be compared to the RCP in effect.

If the calculated RCP results in a reduction in the purchase rate from the previous RCP, any such reduction will be no greater than 10% of the previous RCP.

1. Determine appropriate five-year period. The RCP will be calculated using the 5-year period with the Base Year as the final year of the five. Only those grid-scale solar facilities with an in-service date within this 5-year period will be included in the annual RCP calculation.

If there are no grid-scale solar photovoltaic projects in any particular year of the rolling five-year period described above, the rolling 5--year average will be calculated without a project for that particular year. Calculating the RCP without a project for a particular year (i) is the product of the settlement approved in Decision No. 76295; (ii) is the product of compromise; and (iii) does not establish a precedent for how the RCP should be calculated.

2. Develop/update annual Revenue Requirement for each APS-owned facility. The Company will calculate revenue requirements for each grid-scale solar photovoltaic generation facility owned by the Company that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual designed output of the facility, including degradation, will be used for this calculation. This step provides an annual revenue requirement cost in dollars for each year of the facility's depreciable life.

3. Incorporate applicable Production Tax Credit. All expected available annual Production Tax Credit tax savings (in dollars) for the above APS facilities will be calculated based on expected annual energy production and subtracted from the annual facility cost derived in Step 2 above for each year.

4. Develop/update annual cost of power from each PPA facility. The Company will calculate an annual cost of purchased power for each facility from which APS purchases power under an executed agreement that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual cost for each of these facilities will be calculated separately for the contract life of each PPA using the contract price and the designed output, including degradation, of the facilities, including contractual escalation factors, as appropriate.

5. Calculate individual facility Levelized Cost. The Levelized Cost for each of the facilities will then be calculated using the data derived in Steps 2 through 4 above. The net present value discount rate used in the Levelized Cost calculations will be calculated using the approved after-tax weighted average cost of capital as determined in the Company's most recent rate case. The result of this calculation step will be a Levelized Cost per MWh for each of the facilities.

6. Calculate weighted Levelized Cost for each facility. The weighted Levelized Cost is calculated by multiplying the cost per MWh derived for each facility in Step 5 by the actual Base year energy

production in MWh for each Step 5 facility. The result of this step is an annual weighted cost in dollars for each included facility.

7. Calculate weighted average Levelized Cost for all facilities. The annual weighted average Levelized Cost is determined by dividing the total annual weighted costs for all included facilities by the total Base Year energy production MWh. The result of this step is the rolling historical five-year weighted average Levelized Cost per MWh for grid-scale solar photovoltaic facilities on the APS system before any applicable adjustments.

8. Adjustments. An adjustment is then applied to the annual weighted average Levelized Cost per MWh for Avoided Transmission Capacity cost, Avoided Distribution Capacity cost, and Line Losses as required in Decision No. 75859. For purposes of this Plan of Administration, and subject to future Commission proceedings, the combined adjustment for these three values is set at $0.02/kWh as provided for in Decision No. 76295. This amount is negotiated, does not reflect an actual calculation of system conditions, and establishes no precedent for any future RCP calculations.

7. Procedural Timeline

The Company will provide Commission Staff and other intervening parties with its annual RCP calculation no later than May 1 each year. Interested parties will file comments to the Company's RCP calculation by June 1. Commission Staff will file its Report by July 15 and request that Staff's Report be considered in the August Open Meeting and be approved so that the new RCP calculation is effective on September 1.

8. Confidential Data

Portions of the data used to calculate APS's annual RCP are competitively/highly confidential and cannot be released to the public. Competitively/highly confidential information will be made reasonably accessible to parties so that they may determine that such data supports the RCP calculation and that the RCP calculation complies with Commission orders. Competitively/highly confidential information includes cost and production data for facilities from which APS purchases energy under a PPA agreement.

9. Schedules

Templates of the spreadsheet used to calculate the RCP are attached:

Schedule 1: Annual Resource Comparison Proxy Calculation Summary
Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost
Schedule 3: Individual Plant Annual Cost ($/MWh)
Schedule 4: Individual Plant Energy Production (MWh)
Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost ($000)

Schedule 6: Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits ($000)

Each of these schedules may contain competitively/highly confidential PPA data as indicated.

Renewable Energy ~~Standard~~ Adjustment ~~Schedule~~Charge
Plan of Administration

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1. General Description

This document describes the plan for administering Arizona Public Service Company's (APS or the Company) Adjustment Schedule REAC-1, Renewable Energy Adjustment Charge (Schedule REAC-1). As authorized for APS ~~Schedule REAC-1 is the tariff required~~ by the Arizona Corporation Commission~~'s~~ (Commission) ~~Renewable Energy Standard and Tariff rules (the Rules) approved~~ in Decision No. ~~69127 (November 14, 2006)~~XXXXX (XXX X, XXX), Schedule REAC-1 ~~and codified in A.A.C. R14-2-1801 *et. seq.*, which~~ provides for the recovery of, both, (1) approved renewable energy program ~~the~~ costs ~~incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.[1]~~in compliance with the Commission's Renewable Energy Standard Tariff (REST) rules and (2) approved capital carrying costs for qualified resources consistent with the APS IRP Action Plan.

2. ~~Allowable Costs~~Definitions

All-Source Request for Proposal (All-Source RFP) – A document issued by APS soliciting proposals from qualified parties in which all types of electric resources or energy storage projects that can meet all or part of the needs described in the RFP will be considered equally.

Allowable Costs – Schedule REAC-1 shall recover the following:

(1) The cost of renewable energy programs included in the Company's annual ~~Renewable Energy Standard Implementation Plan (~~RESTP Plan~~)~~, and approved by the Commission, that are not otherwise recovered in base rates or other recovery mechanism. ~~Allowable~~ Costs include, but are not limited to, program development, program implementation, purchased power costs not recovered through the Power Supply Adjustor, customer incentives, customer education and communication, technical assistance and training, marketing, ~~and~~ advertising, administrative and general expense,

(2) The cost of monitoring and evaluation of the programs defined above,

~~[1] The Company's initial Schedule RES was approved by the Commission in Decision No. 70313 (April 28, 2008) and has been revised on an annual basis as described in this Plan of Administration.~~

(3) F~~f~~unds approved by the Commission for Coal Community Transition or similar programs, and

(4) ~~monitoring and evaluation,~~ C~~c~~apital C~~c~~arrying C~~c~~osts for Clean Energy Resources that are in service at the time Schedule REAC-1 rates are approved and are not yet being recovered in base rates or other recovery mechanism, including energy storage and excluding nuclear energy, ~~renewable energy-related capital investments made by APS[2]~~ and other relevant costs where such costs are not otherwise recoverable through an approved RES Implementation Plan.

Applicable Interest – Interest is applied on Balancing Account funds annually at the following rates: any over-collection existing at the time of the adjustor rate calculation will be credited an amount equal to interest at a rate equal to the Company's authorized return on equity (ROE) or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the time of the adjustor rate calculation will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Capital Carrying Costs – Capital carrying costs include (1) a return at the Company's Weighted Average Cost of Capital found by the Commission in the Company's most recent general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits associated with investments being recovered where appropriate and (6) associated operations and maintenance expenses.

Clean Energy Resources – Includes all non-carbon emitting APS-owned resources, including energy storage and excluding nuclear energy.

Earnings Test – Comparison of the Earnings Test Period rate of return with the Earnings Test Threshold. The Earnings Test Period rate of return will be based on APS's most recently filed FERC Form 1, using Earnings Test Period costs, revenues, and other financial information, with certain pro forma adjustments related to surcharges and explicit items removed in the Company's most recently approved rate case applicable to the evaluation year. The Earnings Test applies only to the Clean Energy Resource portion of the Schedule REAC-1 adjustor rate calculation as shown in Section 5 herein.

Earnings Test Period – Historical calendar year represented in the most recently filed FERC Form 1.

Earnings Test Threshold – The ROE authorized in the Company's most recent rate case, with an updated capital structure and cost of debt adjusted to reflect authorized recovery of the Fair Value Increment (FVI) approved in the most recent rate case.

~~[2] Capital carrying costs for any APS renewable energy-related capital investments made in conjunction with projects outside the scope of Decision Nos. 71448, 76295, and 78317 shall not be recovered through Schedule REAC-1 without separate Commission approval.~~

Integrated Resource Planning Action Plan (IRP Action Plan) - The three-year plan required by the Commission's Integrated Resource Planning (IRP) Rules set forth in A.A.C. R14-2-703(H), which is based on the most recent IRP filed by APS and outlines the actions to be taken by the Company on future resource acquisitions.

Renewable Energy Standard and Tariff Rules (REST Rules) – The Commission's Rules, approved in Decision No. 69127 (November 14, 2006) and codified in A.A.C. R14-2-1801 et. seq., which provide for recovery of the costs incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.

Renewable Energy Standard Compliance Report (RES Compliance Report) – The report required by A.A.C. R14-2-1812 et. seq., which is filed on April 1 of each year and describes APS's compliance with the requirements of the REST Rules for the prior calendar year.

Renewable Energy Standard Implementation Plan (RES Plan) – The report required by A.A.C. R14-2-1813 et. seq. as amended by this Plan of Administration, which is filed on November 1 of each year and describes how APS intends to comply with the REST Rules for the next calendar year. The REST Plan will include a description of the Clean Energy Resources to be included in the calculation of the Schedule REAC-1 adjustor rate and will include the calculations showing the derivation of the adjustor rate and the results of the Clean Energy Resources Earnings Test.

Service Schedule 6 – APS's Service Schedule 6, Interconnection Study Services and Fees for Non-FERC Generation Facilities, contains a schedule of fees for feasibility, system impact, and facilities studies for certain generators requesting interconnection to the Company's transmission and/or distribution system. Fees collected by APS for these studies are credited against the Balancing Account for this mechanism as described in Section 4.

3. Clean Energy Resource Eligibility

To be eligible for inclusion in the Schedule REAC-1 adjustor rate, Clean Energy Resources must be consistent with APS's IRP Action Plan and must be acquired through an All-Source RFP process. The All-Source RFP process will be in compliance with the Commission's Procurement Rules set forth in A.A.C. R14-2-705 and 706 and will include the use of an Independent Monitor.

If any eligible Clean Energy Resources generate revenue, such revenue will be included as a credit in the calculation of the Schedule REAC-1 adjustor rate.

Clean Energy Resources to be included in the Schedule REAC-1 adjustor rate will be discussed with stakeholders and interested parties in stakeholder meetings as shown in the Regulatory Timeline (Section 7). A summary of stakeholder meetings and a description of the included resources with relevant supporting documentation will be included in the annual REST Plan.

43. Balancing Account

~~Actual~~ Allowable Costs shall be recorded in a separately maintained Balancing Account. Revenues received by APS through Schedule REAC-1, as well as other relevant revenue (including, but not limited to, ~~forfeited PBI Reservation Deposits and~~payments to APS under

Service Schedule 6 ~~payments~~and any revenue generated by eligible Clean Energy Resources), shall be credited to the Balancing Account.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in the Schedule REAC-1 adjustor rate in the subsequent calendar year.

~~5~~4. Adjustor Components

Schedule REAC-1 shall consist of a monthly kilowatt-hour (kWh) charge applied equally to all Standard Offer and Direct Access service. The kilowatt-hour charge is subject to a monthly ~~surcharge~~adjustor limit calculated for specific customer billing classes as determined by the Company and approved by the Commission.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in Schedule REAC-1 in the subsequent calendar year.

~~6~~5. Determination of the ~~kWh~~ Adjustor Rate and ~~Surcharge~~ Limits for Schedule REAC-1

In accordance with Commission Decision No. 73183, customers who receive an incentive under the Renewable Energy Standard and install their system after July 1, 2012 will pay ~~the~~an applicable monthly ~~surcharge~~ limit. ~~This provision shall be effective in billing cycle 1 after APS reprograms its billing system to accomplish this, or with the March 2013 billing, whichever is first.~~

Schedule REAC-1 shall be revised annually to recover ~~projected~~ Allowable Costs as determined by the Commission through the review and approval process outlined in Section 7 below.~~for the upcoming calendar year, and shall be based on programs and budgets contained in the Company's RES Plan and approved by the Commission.~~ The Schedule REAC-1 kWh rate ~~and surcharge limits~~ shall be designed using projected billing determinants for the ~~same period~~calendar year in which the adjustor rate is expected to become effective. The billing determinants shall include total retail kWh subject to Schedule REAC-1 and the number of customers and associated kWh that are billed under each ~~surcharge~~adjustor limit.

~~7~~6. Review and Approval ~~Process~~

Schedule REAC-1 shall be filed for the upcoming calendar year as part of the Company's RESTP Plan, which is filed on ~~July~~ November 1st each year as ~~set forth in the Rules~~approved in Decision No. XXXXX. Supporting information for the calculation of ~~the kWh~~ rates shall be provided for Staff and interested parties to review. ~~and surcharge limits as shown in Exhibit 1 to this Plan of Administration shall be provided. Schedule REAC-1 shall be updated to reflect the final approved budget for the upcoming year and an updated projected over and under collection in the Balancing Account through the end of the current year.~~

Prior to filing each year, the Company will review the RES Implementation Plan, including new programs and investments, with Commission Staff and stakeholders. Commission Staff will review the information, along with input and comments from interested parties, and will issue a

report and proposed order for Commission approval.

Once approved by the Commission, the Schedule REAC-1 adjustor rate ~~and surcharge limits~~ will be effective each year beginning with billing cycle 1 of the ~~January~~ October revenue month or as otherwise ordered by the Commission and will not be prorated.

Regulatory Timeline	
Prefile Stakeholder Meeting	Early September
Prefile Stakeholder Meeting if desired	Early October
File RES Implementation Plan	November 1
Stakeholder Meeting	Mid-December
Staff Report Target	Mid-August
Open Meeting Target	September
Rate Implementation	October 1

8. Earnings Test

Any requested increase in the Schedule REAC-1 adjustment mechanism related to Clean Energy Resources will be subject to an Earnings Test, which will compare the previous year's unadjusted rate of return for the Earnings Test Period with an Earnings Test Threshold.

If the results of the Earnings Test are higher than the Earnings Test Threshold, the Clean Energy Resources capital carrying cost recovered through Schedule REAC-1 will be limited to the amount corresponding to the Earnings Test Threshold. The amount above the earnings threshold, if any, will be held in the balancing account for recovery through Schedule REAC-1 in a future year.

9. Schedules

APS's annual REST Plan will include attachments and schedules detailing all calculations that develop the proposed REAC-1 adjustor rates.

Schedules outlining the proposed cost and expected generation from RES-related programs and facilities are based on the templates developed by the REST Format Working Group as required in Decision No. 72737 and approved by Staff.

The REST Plan will include the following Schedules that outline the development of the earnings test as attached to this document:

Earnings Test Schedule 1: Annual Earnings Test
Earnings Test Schedule 2: Capital Structure

APS will continue to file the annual RES Compliance Report on April 1 of each year as required by the REST Rules.

Transmission Cost Adjustment
Plan of Administration

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1. General Description

The purpose of the Transmission Cost Adjustment (TCA) is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission (FERC) and at the same time as new transmission rates become effective for Arizona Public Service (APS or Company) wholesale customers. APS shall file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC Informational Filing of its Annual Update of transmission service rates pursuant to its Open Access Transmission Tariff (OATT). This notice shall be filed with the Commission at the same time that APS makes its FERC filing.

The TCA applies to APS's Retail Electric Rate Schedules. For Standard Offer customers, the TCA is applied to the bill as a monthly kWh charge for Residential Service Customers and General Service Customers less than or equal to 20 kW. For all other Standard Offer customers, the TCA is applied to the bill as a monthly kW charge. The charge and modifications to it will take effect in billing cycle 1 of the June revenue month without proration.

APS's Network Integration Transmission Service (NITS) is calculated and filed annually with FERC in accordance with APS's formula rate. The formula rate calculation is specified within the Company's OATT as filed and approved by FERC.

2. Calculations

The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC Informational Filing of its Annual Update of transmission service. NITS rates as determined for the following classes include:

Residential Service Customers
General Service Customers less than or equal to 20 kW
General Service Customers over 20 kW and less than 3 MW
General Service Customers equal to and greater than 3 MW

In addition to NITS, APS charges retail customers for other transmission services in accordance with its OATT. These additional ancillary services include:

Schedule 1 - Scheduling, System Control and Dispatch Service
Schedule 3 - Regulation and Frequency Response Service
Schedule 4 - Energy Imbalance Service
Schedule 5 - Operating Reserve - Spinning Reserve Service
Schedule 6 - Operating Reserve – Supplemental Reserve Service

APS's NITS rates will change annually, where ancillary service charges will change only through a separate filing when made by the Company to FERC.

The total APS OATT rate is the sum of the rates for providing these services. The revenue requirement resulting from the FERC APS OATT rate is collected by APS from its retail customers, partly in base rates and the remaining through the TCA rate.

3. TCA Balancing Account

APS will maintain accounting records that accumulate the difference in revenues anticipated to be recovered by the TCA, as compared to the actual revenues received by the Company through the TCA during the recovery period (June through May). The difference will be recorded to the TCA Balancing Account each month and will be provided annually in Attachment C of the filing. In the event the actual TCA revenues for the recovery period (June through the last billing cycle of May) are more or less than the anticipated revenues for that same period, the over or under collection will be subtracted from or added to the TCA balancing account calculation for the subsequent period.

4. Filing and Procedural Deadlines

APS will file the calculated TCA rates with the Commission each year no later than May 15th, in the form of Attachments A through H as attached to this document and described in Section 5. *Compliance Reports*.

The Commission Staff and interested parties shall have the opportunity to review APS's FERC Informational Filing of its Annual Update of transmission service rates pursuant to the APS OATT Attachment H-2, Formula Rate Implementation Protocols. The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC filing. The new TCA rates proposed by APS will go into effect with the first billing cycle in June (without proration), unless Staff requests Commission review or otherwise ordered by the Commission, and will remain in effect for the following 12-month period.

5. Compliance Reports

APS will provide an annual report to Staff detailing all calculations related to the calculated TCA rates. The reports will include the following Attachments A through H as attached to this document:

Attachment A:	Non-redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment B:	Redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment C:	Numerical inputs used to develop the new TCA-1 rates

Attachment D:	Estimated monthly bill impacts of the new TCA-1 rates
Attachment E:	Table illustrating the percentage demand of each of the classes for the 20XX OATT and 20XX OATT as filed with FERC
Attachment F:	Table illustrating the transmission cost embedded in base rates, the current and proposed TCA rates, and the differences in the current and new rates
Attachment G:	Actual and estimated transmission additions, dollars and estimated O&M for calendar years 20XX through 20XX (1 year actual and 2 years forecast)
Attachment H:	APS's Annual Update of transmission service rates pursuant to the APS OATT as filed with FERC

Tax Expense Adjustment Mechanism
Plan of Administration

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1. General Description

This document describes the plan for administering the Federal and State Income Tax Expense Adjustment Mechanism (TEAM) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on November 9, 2021 in Decision No. 78317 and Decision No XXXX on XXXXX. The TEAM enables the pass-through of income tax effects that materially impact the ~~Company's Test~~Company's Test Year revenue requirements[1] to customers resulting from federal or state income tax legislation. The TEAM will be calculated annually on a prospective basis.

2. Definitions

Annual Tax Expense Adjustment – The Annual Tax Expense Adjustment represents the amount to be passed through to jurisdictional retail customers in the subsequent ~~twelve month~~twelve-month period and is applied to customer bills via a $ per kWh adjustment.

Base Revenue Requirements Change – The change in the Company's Base Revenue Requirements as a result of any Federal and/or State income tax reform legislation will be measured as the change in:

a. The Federal and/or State Income Tax Rate-Test Year as compared to the Federal and/or State Income Tax Rate-Revised as applied to the Company's Adjusted –Test Year in Decision No. ~~78317~~XXXXX;
b. Annual amortization of any resulting deficient or excess deferred income tax regulatory account compared to the Company's ~~Adjusted Test~~Adjusted Test Year in Decision No.~~78317~~XXXXX; and

[1] "Material impacts" is defined as changing APS's revenue requirement by more than $5 million.

c. New permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted Test Year in Decision No. ~~78317~~XXXXX.

Federal Income Tax Rate-Revised – The Federal marginal corporate income tax rate as set forth in relevant legislation.

Federal Income Tax Rate-Test Year – The Federal marginal corporate income tax rate of 21% in effect and utilized in the revenue requirements as approved by the Commission in Decision No. ~~78317~~XXXXX.

Forecasted Retail kWh Sales – The forecasted calendar year energy (kWh) sales served under applicable ACC jurisdictional retail electric rate schedules. A true-up reconciliation of the forecasted data will be completed in the following year through the Balancing Account.

Protected Deficient or Excess ADIT – Changes in net Accumulated Deferred Income Taxes (ADIT) due to the Federal Income Tax Rate-Revised or State Income Tax Rate – Revised which must be passed through to Customers under specific IRS or State requirements (such ~~as differences~~as differences between regulatory depreciation calculations and tax depreciation calculations).

State Income Tax Rate-Revised – The State marginal corporate income tax rate (net of Federal tax benefits) as set forth in relevant legislation.

State Income Tax Rate-Test Year – The State marginal corporate income tax rate (net of Federal tax benefits) of 3.75% in effect and utilized in the revenue requirements as approved by the Commission in Decision No. ~~78317~~XXXXX.

Unprotected Deficient or Excess ADIT – All changes in net ADIT due to the Federal Income Tax Rate-Revised or State Income Tax Rate - Revised that are not Protected Deficient or Excess ADIT. These changes may be passed through to Customers as determined by the Commission.

3. Calculation of TEAM

The Annual Tax Expense Adjustment is calculated annually and represents the amount to be passed through to jurisdictional retail customers. The adjustment is calculated based on the Company's Base Revenue Requirements Change as defined above.

The Annual Tax Expense Adjustment may include up to three separate components:

Phase I Component. The Phase I component represents the Base Revenue Requirements Change due to the difference between the Federal and/or State Income Tax Rate-Revised and the Federal Income Tax Rate-Test Year.
Phase II Component. The Phase II component represents the Base Revenue Requirements Change due to Unprotected Deficient or Excess ADIT as defined above which was recorded on the Company's balance sheet as of the effective date of relevant Federal or State tax legislation

Phase III Component. The Phase III Component represents the Base Revenue Requirements Change due to Protected Deficient or Excess ADIT as defined above. Additionally, the Phase III Component will also address adjustments necessary to both Protected Deficient or Excess ADIT and Unprotected Deficient or Excess ADIT to reflect differences between tax positions reported in the Company's regulated books of account as of the effective date of relevant Federal tax legislation and positions which will be taken on the Company's Federal tax return for the same time frame.

The TEAM $ per kWh rate is calculated by dividing the Annual Tax Expense Adjustment by the Forecasted Retail kWh Sales. For billing purposes, the TEAM Phase I, Phase II, and Phase III Components will be combined.

As determined in Decision No. 76601 (March 5, 2018), Customers served under the Company's Rate Rider AG-X (Alternative Generation) will receive 75.64% of the TEAM $ per kWh rate as calculated above. Customers served under the Company's Experimental High Load Factor Rate Schedules HLF-1, HLF-2, and HLF-3 will receive 86.84% of the TEAM $ per kWh rate.

4. TEAM Balancing Account

APS will maintain accounting records that accumulate the difference between each Component, as necessary, of the calculated Annual Tax Expense Adjustment as compared to the actual amounts applied to customers' total bills through the total TEAM $ per kWh adjustment during the prior calendar year. Additionally, as a result of utilizing Forecasted Retail kWh Sales, the balancing account will contain a true-up component in which estimated balances will be replaced with actual balances for the prior year filing.

Differences will be recorded to the TEAM Balancing Account each month and will accrue interest at the Company's applicable cost of short-term debt.

5. Compliance Reports

Each year until the TEAM is terminated, on or before March 1 APS will provide a report to Staff and the Residential Utility Consumer Office showing the status of the TEAM Balancing Account described in Section 4 above.

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all service schedules and rate schedules including but not limited to rider and adjustor schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. **Application for Service**

Before supplying service, APS will verify the identity of Applicant. Applicants may be required to appear at the Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and the Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 **Grounds for Refusal of Service** – APS may refuse service if any of the following conditions exist:

(A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to the Company.

(B) A condition exists that, in the Company's judgment, is unsafe or hazardous.

(C) The Applicant has failed to meet the Company's security-deposit requirements outlined in Section 3.

(D) The Applicant is known to be in violation of a Company Tariff.

(E) The Applicant fails to furnish the funds, service, equipment, ~~rightsofway~~rights-of-way or easements required to serve the Applicant that APS has specified as a condition for providing service.

(F) The Applicant falsifies his or her identity for the purpose of obtaining service.

(G) Service is already being provided at the address for which the Applicant is requesting service.

(H) A prior Customer, who will reside at or benefit from service at the Applicant's P~~p~~remises, owes APS a delinquent bill for the same class of service from the same or a prior service address.

(I) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

2. **Service Establishment**

A Service Establishment Charge of $0.00 for residential or $0.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month. All service establishment requests are subject to availability; there is no guarantee that the Company will have the ability to provide service establishment, re-establishment, or reconnection of service on same-day requests or requests made outside of regular business hours. For situations where the Company is unable to complete same-day or after-hours requests, service establishment will be scheduled for the next available business day.

2.1 **Multiple Connects –** If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service Establishment Charge once for every two Delivery Points.

2.2 **After-hours Connect –** The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $0.00 for residential with standard metering, $0.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 **Same-Day Connect –** The Customer must also pay a same-day connect charge of $0.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by the Company, waive the same-day fee.

2.4 **Non-Standard Service Request –** The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when the Customer requests

services that do not meet the definition of Service Establishment as defined in A.A.C. R14-2-203.D.3 and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives the Company uses to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 **Waiving of Service Establishment Charge** – The Company may waive the Service Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with the Company.

3. **Establishing Credit, Security Deposits and other forms of Credit Assurance**
When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to provide a security deposit to secure payment of bills for service.

3.1 **Residential Establishment of Credit** – APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

(A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.

(B) The Company receives an acceptable credit rating, as determined by the Company, for the Applicant from a credit-rating agency used by the Company.

(C) The Applicant can produce a letter regarding verification of credit from an electric utility that provided service of a comparable nature to the Applicant within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.

(D) If, in lieu of a security deposit, the Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.

3.2 **Nonresidential Establishment of Credit –** All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

(A) The Applicant had service of a comparable nature with the Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.

(B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 **General Deposits Guidelines –** If a security deposit is required, a separate deposit may be required for each service location.

(A) A Customer's security deposit will not preclude the Company from terminating an agreement for service or suspending service if the Customer fails to meet service-agreement obligations.

(B) The Company may choose to accept less than the full deposit required at the time ~~of~~ service is ~~establishment~~ established based on the Customer's financial condition.

(C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, the Company may require the Customer to establish or reestablish a security deposit.

3.4 **Residential Security Deposits –** Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by the Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 **Nonresidential Security Deposits –** Nonresidential security deposits will not exceed two and one-half times the Customer's maximum monthly billing as estimated by the Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by the

Company based on the results of using a credit-scoring worksheet. The Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 **Deposit Interest –** Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 **Deposit Refunds –** If the Customer terminates all service with the Company, the Customer's security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days of the Customer's final bill due date.

3.8 **Residential security deposits** or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

(A) **Nonresidential security deposits** and noncash deposits on file with the Company will be reviewed after 24 months of service and will be returned if:

(1) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(2) The Customer's financial condition does not warrant an extension of the security deposit.

4. **Rates**

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 **Rate Selection –** APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, the Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 **Rate Information –** APS will ~~provide~~make available, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in the Company's Tariff affecting those Customers.

4.3 **Optional Rates** – Optional rate schedules are available for certain classes of service. After establishing service, a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. For non-residential customers, ~~No~~ no further rate schedule changes may be made within the succeeding ~~12 month~~12-month period~~.~~ If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

~~4.3~~4.4 The Company may, at its discretion, place a Customer on an available rate schedule (consistent with the existing meter's ability to measure service) while the Company seeks satisfactory and unassisted access to the Company's equipment if the Customer refuses to allow meter access. Please also see 7.3(E).

5. **Billing**

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at the Company's option.

5.1 **Payment of Bills** – The Customer is responsible for paying bills until service is ordered discontinued and the Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services are involved, until the Company has had reasonable time to process the disconnect request.

5.2 **Failure to Receive Bills or Notices** (including notices of disconnection) which have been properly placed in the United States mail to the Customer's last address on file or sent by or through alternative methods of communications~~billing forms~~, such as electronic mail to the Customer's last email address on file, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the C~~c~~ustomer of their obligations.

5.3 **Incentive for Electronic Payments** – A monthly incentive of $0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

5.4 **Billing Errors** – When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.

5.5 **Corrected Charges for Overbilling –** Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by the Company.

5.6 **Corrected Charges for Underbilling –** Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and ~~is~~ will not be limited to three or six months ~~as applicable~~.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by the Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with the Customer to establish a payment plan that is acceptable to the Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

5.7 The Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. **Collection Policy**

The following collection policies apply to all Customer accounts:

6.1 **Delinquent Bills –** All bills rendered by the Company are due and payable no later than 21 calendar days from the billing date. Any payment not received within this time frame is delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of the Company's termination procedure. The Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.

6.2 **Late Charges –** All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 **Transfer of Outstanding Bills –** If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to the Company, the Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, the Company has the right to collect the full amount owed from any one of the Customers.

6.4 **Dishonored Payments –** If the Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, the Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to the Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The Company will waive the $15.00 Dishonored Payment fee if the Customer has not, in the previous 12 months, had a dishonored payment.

(C) The tender of a dishonored payment does not relieve the Customer of the obligation to pay the Company under the original terms of the bill, nor does it defer the Company's right to terminate the Customer's service for nonpayment of bill(s).

(D) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, the Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 **Collection Agency Referrals –** All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, the Customer may be responsible for the associated collection-agency fees incurred.

7. **Termination of Service**

7.1 To avoid termination of service: The Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to the Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company. APS may also require payment of Same-Day and After-Hours charges prior to restoring service.

7.3 **Termination of Service ~~With~~ with Notice** – APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if the Company has met the notice requirements established by the Arizona Corporation Commission:

(A) The Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.

(B) ~~A~~ The Customer's failure to pay a Delinquent Bill for services provided by Company.

(C) The Customer's breach of a written contract for service.

(D) The Customer's failure to comply with the Company's deposit requirements.

(E) The Customer's failure to provide the Company with satisfactory and unassisted access to the Company's equipment.

(F) When necessary to comply with an order of any governmental agency having jurisdiction.

(G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the P~~p~~remises.

(H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.

(I) The Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

(J) When the Company learns of the unauthorized resale of utility equipment or services by the Customer.

7.4 **Termination of Service Without Notice** – Notwithstanding subsections 7.1, 7.3, 7.5, and 7.7, the Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

(A) An obvious hazard to the safety or health of the Customer, the general population or the utility's personnel or facilities;

(B) The Company has evidence of Meter Tampering or fraud related to the Customer or the service address; or

(C) The Customer fails to comply with the curtailment procedures imposed by the Company during a supply shortage.

7.5 **Termination of Service for Dishonored Payment** – Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, ~~or~~ certified funds, or cashier's check. If Customer has already received a final notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

(A) When the Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.

(B) When the Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 **Termination ~~Process~~ Charges** – The Company will require payment of a Field Call Charge of $0.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

7.7 **Residential Service Termination Process**

(A) Except as provided in subsection 7.4, the Company shall not disconnect residential service to a Customer:

(1) From June 1 through October 15;

(2) If the C~~c~~ustomer has paid at least half of the C~~c~~ustomer's Delinquent Bill balance within the last 25 days;

(3) Due to a C~~c~~ustomer's failure to pay the disputed portion of a bill if the C~~c~~ustomer has complied with A.A.C. R14-2-212(B);

(4) If the C~~c~~ustomer's Delinquent Bill balance is less than or equal to $300.00; or

(5) If the C~~c~~ustomer can establish, on an annual basis, through medical documentation that, in the opinion of a licensed medical practitioner:

a. Termination would be especially dangerous to the health of the Ccustomer or a permanent resident residing at the Ccustomer's service address; or
b. If life support equipment used in the home is dependent on utility service for operation of such apparatus.

(B) The Company shall provide notice of the following, using the Ccustomer's preferred method of communication on file, to a Ccustomer whose service would be disconnected except for subsection 7.7(A)(1):
(1) The ~~customer~~ Customer would have been disconnected if not for subsection 7.7(A)(1);
(2) The reason ~~that~~ the Company is not permitted to disconnect service;
(3) The ~~customer's~~ Customer's continued financial responsibility for the charges accruing to the account for energy used;
(4) The potential actions the ~~customer~~ Customer may take to prevent the disconnection of service when subsection 7.7(A)(1) no longer applies; and
(5) The requirement to enter into a payment plan as specified in subsection (D).

(C) The Company shall not disconnect residential service unless the Company's office is open to the public on the day of disconnection and the day following the day of disconnection.

(D) A ~~customer~~ Customer with a Delinquent Bill balance of over $75 whose service disconnection was prevented by subsection 7.7(A)(1) shall be automatically placed on a six-month deferred payment arrangement prior to beginning the service termination process once the no disconnect period set forth in subsection 7.7(A)(1) has ended. The Company shall not impose any late fees or interest on any past due amounts that accrued during the no disconnect period.

(E) If a residential Customer is delinquent on an account and has a cash deposit with the Company, the Company shall use the deposit to pay the delinquent amount before disconnecting service, then allow the ~~residential customer~~ Customer time to repay the deposit in installments over a period of six months.

8. **Metering & Metering Equipment**

8.1 **Standard Metering** – The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All ~~customers~~ Customers will be served using the Company's standard metering equipment unless:

(A) ~~t~~The ~~customer~~ Customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) T~~t~~he ~~customer~~ Customer meets all eligibility requirements for non-standard metering and ~~voluntarily~~ requests non-standard metering.

8.2 **Non-Standard Metering** – The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to ~~customers~~ Customers who select a non-standard meter.

8.3 **Non-Standard Metering Eligibility** – Only residential ~~customers~~Customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or ~~customers~~ Customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 **Non-Standard Metering Charges** – The following charges will apply when a ~~customer~~ Customer ~~voluntarily~~ requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for ~~customers~~ Customers with existing AMI meter.

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see Section 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 **Discontinuation of Non-Standard Metering** – The Company may replace a non-standard meter with a standard meter, without notifying the ~~customer~~ Customer prior to replacement, under any of the following conditions:

(A) The Company employees observe or have evidence of a safety hazard to employees, ~~customers~~Customers, or the Company's or ~~customer~~ Customer property.

(B) The Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) The Company has evidence of unauthorized resale of electricity.

(D) The Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to the Company equipment, and physical threats such as weapons or dogs.

~~(E)~~ All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 **Measuring Customer Service** – All energy sold to the Customer by the Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by the Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 **Meter Rereads** – When requested by a Customer, APS will reread the C~~c~~ustomer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 **Meter Testing** – APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon a Customer's request. If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 **Meter Test Charge** – If the Meter is found to be within the plus or minus 3% limit, the Company may charge the Customer $44.00 plus applicable adjustments for a Customer-requested Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

(A) The ~~company~~ Company will waive the Meter Test Charge if the Customer has not, within the previous 12 months, requested a meter test that was found to be within the plus or minus 3% limit.

8.10 **Meter Tampering** – If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion, will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by the Company.

9. **Service Installations & Metering –** The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to the Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

9.1 **Customer Equipment –** The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for the Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by the Company. In circumstances where a clearance is not required by law, the Company may require the Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to the Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining the Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

9.2 **Special Meter-Reading Device –** Where a Customer requests, and the Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

9.3 **Totalized Metering and Billing –** The Company normally meters and bills each site separately. But, at the Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at the Company's option, be considered a single site as specified in the Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

9.4 **Service Connections –** The Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

(A) For overhead service, the Point of Delivery is where the Company's service conductors terminate at the Customer's weatherhead or bus rider.

(B) For underground service, the Point of Delivery is where the Company's service conductors terminate in the Customer's or development's service

equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing the Company's underground service conductors.

(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and the Company, only authorized employees or agents of the Company ~~or the Load Serving~~are permitted to make and energize the connection between the Company's service wires and the Customer's service entrance conductors. APS employees must carry the Company-issued identification that they will show on request.

10. **Customer Obligations**

10.1 **Load Characteristics** – The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customers must meet power factor requirements as specified in the applicable rate schedules.

10.2 **Easements** – All suitable Easements or rights-of-way required by the Company for any portion used~~of an extension~~ to serve ~~a~~ Customer(s), which ~~is~~ are either on sites owned, leased, or otherwise controlled by the Customer(s) or developer(s), or other property required for the Company's use~~extension~~, will be furnished in the Company's name by the Customer(s) without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All Easements or rights-of-way granted to, or obtained on behalf of, the Company will contain terms and conditions that are acceptable to the Company. Notwithstanding the terms of a written ~~Easment~~Easement or right-of-way, ~~W~~when the Company discovers that a~~the~~ Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, a ~~11.~~djacent to or within an Easement or right-of-way or adjacent to Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with the Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, the Company will notify the Customer or the Customer's agent and may take whatever actions are necessary

to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. The Company will notify the Customer in writing ~~of the violations~~before taking such action.

10.3 **Access for Repair, Maintenance and Service Restoration –** The Company's authorized agents must have satisfactory unassisted, ~~24~~ 24 ~~hour~~ hour-~~a~~ a-day, seven days a week access to the Company's equipment located on the Customer's sites for the purpose of repair, maintenance, and service-restoration work that the Company may need to perform.

10.4 **Access for Install, Inspect, Read, or Remove –** The Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all ~~reasonable~~ hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 **Trip Charge –** A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

(A) The ~~company~~ Company will waive the Trip Charge if, within the last 12 months, there have not been any instances where an authorized Company representative traveled to a site and was unable to complete the Customer's service request because of lack of access to the Point of Delivery.

10.6 **Six Months No Access –** If the Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then the Company has sufficient cause to terminate service or deny any rate options where, in the Company's opinion, access is required.

10.7 **Remedies –** The remedy for unassisted access will be at APS's discretion and may include the installation by the Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for the Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

11. **Company Obligations**

11.1 **Customer-Specific Information** – Customer-specific information will not be released without the Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with the Company if the goods or services will help the Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to the Company.

11.2 **Service Voltage** – The Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208.F. The Company may deliver service for special applications at higher voltages, with prior approval from the Company's Engineering Department and in accordance with the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. **Limitations on Liability of Company**

12.1 **General Liability**

(A) The Company will not be responsible for any third-party claims against the Company that arise from a Customer's use of the Company's electric services or the Company's provision of electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

(B) A Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

(C) Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to a Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of

the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

(D) In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue, loss of current or prospective business opportunities, lost profits and lost rent) of any kind whatsoever regardless of the cause or foreseeability thereof.

(E) The Company will not be responsible in any occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

12.2 **Service Interruptions**

(A) The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 12.3(A) or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment or to eliminate the possibility of damage to the Company's property or to the person or property of others.

(B) Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this interruption or limitation will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

(C) The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

(D) In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(E) The use of electric energy upon the Customer's Premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

12.3 **Force Majeure**

(A) Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

(1) flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

(2) accident or explosion;

(3) war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

(4) acts of God;

(5) interference of civil and/or military authorities;

(6) strikes, lockouts or other labor difficulties;

(7) vandalism, sabotage or malicious mischief;

(8) usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

(9) breakage, failure, or accidents to equipment or facilities; or

(10) lack, limitation or loss of electrical or fuel supply; or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

(B) A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

(C) Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

~~12.1 **Service Interruptions** Company is not liable to the Customer for any damages caused by Load Serving Electric Service Provider's equipment or failure to perform, fluctuations, interruptions, or curtailment of electric service, except where caused by Company's willful misconduct or gross negligence.~~

~~(A) Company may, without incurring any liability, suspend the Customer's electric service for periods reasonably required to permit Company to accomplish repairs to, or changes in, any Company's facilities.~~

~~(B) The Customer is responsible for protecting Customer's own sensitive equipment from harm caused by variations or interruptions in power supply.~~

~~(C) If a national emergency or local disaster results in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.~~

~~12.2 **Use of Service or Apparatus** The Customer will save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or their use on the Customer's side of the Point of Delivery. Company has the right to suspend or terminate service if Company learns of service use by the Customer under hazardous conditions.~~

~~(A) The Customer will exercise all reasonable care to prevent loss or damage to Company property installed on the Customer's site for the purpose of supplying service to the Customer. The Customer is responsible for payment for loss or damage to Company property on the Customer's site arising from neglect, carelessness, or misuse, and will reimburse Company for the cost of necessary repairs or replacements.~~

~~(B) The Customer is responsible for payment of any equipment damage or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by passing the Meter.~~

~~(C) The Customer is responsible for notifying APS of any failure in Company's equipment.~~

~~12.3 **Removal of Facilities** Upon termination of service, Company may, without liability for injury or damage, dismantle and remove its facilities,~~

~~installed for the purpose of supplying service to the Customer, and Company will have no further obligation to serve the Customer.~~

13. **Successors and Assigns –** Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and the Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by the Company.

14. **Warranty –** There are no understanding, agreements, representations, or warranties, expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by the Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of the Company in connection with sales and deliveries.

15. **Direct Access Service –** *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*
    15.1 **Direct Access Service Request (DASR) –** A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (~~"~~ESP~~")~~ submitting the DASR each time the Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.
    15.2 **Direct Access Service –** Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.
    (A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.
    (B) If a Customer returning to Standard Offer Service, in accordance with the rules, regulations and orders of the Commission, was not given the required

notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer ~~s~~Service.

(C) Unpaid charges incurred before the Customer selects Direct Access Service will not delay the Customer's request for Direct Access Service. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to the Company under the Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, the Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where the Company is the MRSP, the Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of the Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 **Direct Access Deposits –** If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under the Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that the Company is providing bundled electric service.

15.4 **Direct Access and Company Equipment**

(A) **Meters –** A Meter Service Provider (MSP) or its authorized agents may remove the Company's metering equipment under the Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to the Company or returned damaged will result in charge(s) to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) **Lock-rings –** The Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and

conditions of the Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If the Company must replace 10% of the issued keys within any 12-month period because of loss by the MSP's agent, the Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock-ring keys must be returned to the Company within five working days if the MSP or its authorized agents are:

(1) No longer permitted to remove Company Meters under the conditions of the Company's Schedule 10;
(2) No longer authorized by the Arizona Corporation Commission to provide services; ort
(3) The ESP Agreement has been terminated.

(C) **Site Meetings –** If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. The Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If the Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Date is the date the statement was created either in electronic or paper form as shown on the bill regardless of the postmark, mailing, or electronic transmittal date.

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30 30-day intervals. [A.A.C. R14-2-201-(5)]

Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company Holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, Christmas Eve, Christmas Day, and New Year's Eve.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (22 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(~~12~~13)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on a Customer's property. [A.A.C. R-14-2-201-(~~13~~14)]

Easement means the right to use~~a property owner ("Grantor") grants the right to use the owner's~~ land owned by~~to~~ another party by grant or as allowed by law. An easement gives the Company the right to have Company lines or facilities on property not owned by the Company. This allows the Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity and for other purposes. The owner~~Grantor~~ may continue to use the land in ~~along~~ the easement as provided by a written easement or by law~~within certain limitations~~.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and the Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not ~~apply~~apply, and service will automatically be

transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with the Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(~~23~~27)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(~~25~~29)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from the Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(30~~26~~)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(31~~27~~)]

On-site means on a single Premises served by the Company's facilities.

Premises means all of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by alleys, canals, streets, railways, or other public rights-of-way.

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(35~~1~~)]

Working Day means a weekday~~s~~ (during normal business hours) that is not designated as a Company holiday.

~~**Tariffs** mean the documents filed with the Arizona Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products. [A.A.C. R14-2-201(42)]~~

Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$0.00	2
Nonresidential Service Establishment Charge	$0.00	2
After hours Charge – Residential Standard Metering	$0.00	2.2
After hours Charge – Residential Non-Standard Metering	$0.00	2.2
After hours Charge – Nonresidential	$164.00	2.2
Same Day Connect Charge	$0.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
Electronically Transmitted Payment Discount	($0.48)	5.3
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$0.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering – Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9
Trip Charge – Residential	$22.00	10.5
Trip Charge – Nonresidential	$26.00	10.5

General Description

The following Terms and Conditions and any changes authorized by law will apply to the purchase of electric energy under the established rate(s) applicable at time of purchase. These Terms and Conditions will be considered a part of all Arizona Public Service Company's (APS or Company) rate schedules for purchases except where specifically changed by written agreement.

1. Definitions

1.1 Point of Interconnection - The point where Company's service conductors are connected to Customer's service conductors.

1.2 Qualifying Facility (QF) - Any cogeneration or small power production facility that meets the criteria for size, fuel use, efficiency, and ownership as stated in 18 C.F.R., Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

1.3 Purchase Agreement - The agreement between Customer and Company detailing the provisions for the purchase of electric energy by Company from Customer's QF, and the sale, if any, of power by Company to Customer.

1.4 Cogeneration Facility - Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

1.5 Small Power Production Facility - A facility that uses primarily biomass, waste, or renewable resources; including, but not limited to, wind, solar, and water to produce electric power.

2. Customer Obligations

2.1 Customer agrees not to begin interconnected operation of its QF with Company's system until the installation has been inspected by an authorized Company representative and final written approval to begin interconnected operation is received from Company. Customer will give reasonable notice to Company when initial startup is to begin. Company has the right to have a representative present during initial energizing and testing of Customer's system.

2.2 Customer will own and be fully responsible for the costs of designing, installing, operating and maintaining the following:

(A) The QF in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.

(B) Control and protective devices to protect its facilities from abnormal operating conditions such as, but not limited to, electrical overloading, abnormal voltages,

and fault currents. Such protective devices will promptly disconnect the QF from Company's system in the event of a power outage on Company's system.

(C) A gang operated load break disconnect switch, capable of being locked in a visibly open position that will completely isolate the QF from Company's system. Such disconnect switch will be installed in a place easily accessible to Company's personnel. Company will have the right to lock open the disconnect switch without notice to Customer when interconnected operation of the QF with Company's system could adversely affect Company's system or endanger life or property.

(D) Interconnection facilities on Customer's premises as may be required to deliver power from Customer's QF to Company's system at the agreed Point of Interconnection.

2.3 Electric sales to Company must be single or three phase, 60 Hertz, at one standard voltage (12,500; 2400/4160; ~~480;~~ 277/480; 120/240 or 120/208 volts as may be selected by Customer subject to availability at the premises). Customer's facilities will also maintain a minimum 90% leading to 90% lagging power factor as measured at the Point of Interconnection.

2.4 The electrical output of Customer's QF will not contain harmonic content which may cause disturbances on, or damage to, Company's electrical system, or other party's systems, such as, but not limited to communication systems.

2.5 Customer will operate and maintain the QF in accordance with those practices and methods, as they are changed from time-to-time, that are commonly used in prudent engineering and electric utility operations and will operate the QF lawfully and in a safe, dependable, and efficient manner.

2.6 Prior to actual installation, Customer will submit to Company for review and advance written approval, written equipment specifications and detailed plans for the installation and operations of its QF, interconnection facilities, control and protective devices and facilities to accommodate Company's meter(s). After Company's approval Customer will not change or modify equipment specifications, plans, control and protective devices, metering and in general the QF's system configuration. If Customer desires to make changes or modifications, Customer will resubmit to Company plans describing desired changes or modifications. No such change or modification may be made without the prior written approval of Company.

2.7 In the event it is necessary for Company to install interconnection facilities on its system (including, but not limited to control or protective devices, or any other facilities) in order to receive or continue to receive or to deliver electric power under the terms of the Purchase Agreement, Company will inform Customer of the cost in advance of incurring the costs of such facilities and Customer will reimburse

Company for the costs incurred by Company in connection with such facilities to the extent that said costs exceed those normally incurred by Company with respect to those Customers which it serves who do not have self generation facilities.

2.8 If Customer utilizes the Company's system to facilitate start-up of its QF, the voltage flicker level will not exceed Company standards.

3. Metering Provisions

3.1 Customer will provide and install at no expense to Company, and in accordance with Company's service standards, meter sockets and metering cabinets in a suitable location to be determined by Company's representatives.

3.2 Company will furnish, own, install and maintain all meters that register the sales of power to, and the purchases of energy from Customer. The responsibility for the costs of providing and maintaining the required meters will be as outlined in the applicable Rate for Purchase, or as specified in the Purchase Agreement.

3.3 The readings of all said meters will be conclusive as to the amount of electric power and energy supplied to the QF and/or purchased by Company unless, upon test, the meters are found to be in error by more than 3%. The expense of any meter test requested by Customer will be borne by Customer unless such test shows the meter(s) to be in error by more than 3%.

4. Mutual Understandings

4.1 Company will be allowed to install on Customer's premises any instrumentation equipment for research purposes. Such equipment will be owned, furnished, installed and maintained by Company.

4.2 Company's approvals given pursuant to the Purchase Agreement will not be construed as any warranty or representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective devices or the design, construction, installation or operation thereof.

4.3 Company (including its employees, agents, and representatives) will have the right to enter Customer's premises at all reasonable times to (a) inspect Customer's QF, protective devices and to read or test instrumentation equipment that Company may install, provided that as reasonably possible, notice is given to Customer prior to entering its premises; (b) maintain Company equipment relative to the purchase of electric energy from Customer; (c) read or test the meters; and (d) disconnect the QF without notice if, in Company's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or Company's facilities or other

customers' or third parties' property and facilities from damage or interference caused by Customer's QF, or improperly operating protective devices.

4.4 All suitable easements or rights-of-way (required by Company in order to accommodate inter-connection of Company's system with the QF), which are either on premises owned, leased or otherwise controlled by Customer, or upon other property, will be furnished in Company's name by Customer without cost to or condemnation by Company and in reasonable time to meet the requirements of the Purchase Agreement. All easements or rights-of-way obtained on behalf of Company will contain such terms and conditions as are acceptable to Company.

4.5 Company is not obligated to pay for electric energy or capacity from Customer during any periods when such purchases would result in costs greater than those which Company would otherwise incur had Company generated said energy itself or purchased the energy from another source. Company will give reasonable notice to Customer when such periods exist, so that Customer can discontinue deliveries of energy to Company or elect to continue to sell to Company at a rate, lower than the standard purchase rate, estimated to be the avoided system cost for the period during which such situations exist.

4.6 Company will not install and maintain any lines or equipment on Customer's side of the Point of Interconnection except its meter (and possibly some research equipment). For the mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the interconnection between Company's system and that of Customer's QF. Such employees carry credentials which they will show to Customer upon request.

4.7 The particular rate for purchases applicable to a QF may be dependent on the system configuration of its facilities. Because of the varied and diverse requirements and operating characteristics associated with such facilities, it will be the QF's responsibility to evaluate and determine which system configuration and attendant purchase rate is most appropriate. Company will cooperate with Customer by providing suitable information to enable the Customer to assess the options available; provided, however, that no such information or assistance will be deemed a representation or warranty by Company with respect to the contents of such information or any particular option available to Customer.

4.8 Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules or at Company's option.

4.9 The interconnection of Company's system with that of Customer will normally be arranged to accept only one type of standard service at one Point of Interconnection. However, if Customer's QF requires a special type of service (e.g., supplemental,

back-up, maintenance or interruptible power in addition to its normal service), or its sales to Company are at a different voltage level than that of its purchases from Company, such service(s) will be provided pursuant to the specific terms outlining such requirements in the Purchase Agreement, applicable rate schedules, and/or other supplemental or special terms and conditions governing such service.

4.10 Each premise owned or controlled by Customer which is served by Company under the Purchase Agreement will be metered and billed separately. As used herein, the term "premises" will be deemed to mean a single tract of land owned or controlled by Customer, or separate adjacent or contiguous tracts of land owned or controlled by Customer, operated by it as one tract under the same name or as part of the same business, and not separated by any private or public lands or rights-of-way owned or controlled by third parties.

4.11 All bills rendered for Company services provided to Customer under the provisions of the Purchase Agreement are due and payable upon presentation and are past due fifteen calendar days after mailing of bill. Company reserves the right to suspend or terminate Customer's service for non-payment of service bills past due, for non-payment of interconnection charges, and for non-payment of meter test charges. Past-due service bill amounts, past-due interconnection charges and past-due meter test charges, are subject to an additional charge at the rate of 1-1/2% per month during the period of delinquency.

5. Service offered under Special Agreement

Purchases will be made from Customer's QF in accordance with the Purchase Agreement, these terms and conditions and any changes required by law, regulation, rule, or order of applicable governmental authority, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of QF's, whose requirements are of unusual size or characteristics, additional or special rate and contract arrangements may be required.

6. Regulatory Authority

The rates, terms and other contract provisions governing electric power sold to Customer and the rates or other contract provisions for purchases by Company from Customer are subject to the jurisdiction of the Arizona Corporation Commission (ACC) and nothing contained herein will be construed as affecting or limiting in any way the right of Company (a) to make unilateral filings of changed rates, terms and other contract provisions, which will be effective when filed, or within a specified number of days thereafter as specified therein, such rates or other contract provisions specified in such filing to be subject to modification if required by a final decision of the ACC, or (b) to unilaterally make application to the ACC for changes in such rates or other contract provisions, following a hearing and decision as permitted by law and the ACC's rules and regulations.

7. Indemnity and Insurance

Each Party hereby agrees to indemnify the other Party, its officers, agents, and employees against all loss, damages, expenses and liability to third persons for injury to or death of person or injury to or loss of property, proximately caused by the indemnifying Party's construction, ownership, operation, or maintenance of, or by failure of, any of such Party's works or facilities used in connection with the Purchase Agreement. The indemnifying Party will, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party will also pay all costs and expenses that may be incurred by the other Party in enforcing this indemnity.

8. Uncontrollable Forces

No Party will be considered to be in default in the performance of any of its obligations under the Purchase Agreement (other than obligations of said Party to pay sums to be paid by it hereunder, and other costs and expenses) when a failure of performance will be due to an uncontrollable force. The term "uncontrollable force" will be any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, strikes, labor or material shortage, sabotage, restraint by court order or public authority, and action or non-action by or inability to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it will be unable to overcome. Nothing contained herein will be construed so as to require a Party to settle any strike or labor dispute in which it may be involved. Either Party rendered unable to fulfill any of its obligations under this Agreement by reason of an uncontrollable force will give prompt written notice of such fact to the other Party and will exercise due diligence to remove such inability with all reasonable dispatch.

9. Notices

Any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other may be so given by certified or registered mail, addressed to the Party or personally delivered to the Party at the place designated in the applicable section of the Purchase Agreement. Changes in such designation may be made by notice similarly given.

10. Conflicts

In case of an inconsistency or conflict between any provision of the Purchase Agreement, a rate schedule or these terms and conditions, the inconsistency will be resolved by giving priority to the Purchase Agreement, the rate and then the terms and conditions in said respective order.

11. Successors and Assigns

Purchase Agreement will be binding upon and for the benefit of the successors and assigns of Customer and Company, but no assignment by Customer will be binding until accepted in writing by Company (which acceptance will not be unreasonably withheld) and until the assignee in writing assumes the obligations of Customer under the Agreement.

General Description

This schedule establishes the terms and conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1. **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.
1.2. **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.
1.3. **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.
1.4. **Conversion** means converting overhead distribution facilities to underground facilities.
1.5. **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.
1.6. **Doubtful Permanency means** a customer who, in the opinion of the Company, is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.
1.7. **Economic Feasibility** means a determination by Company that the estimated annual

revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8. **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9. **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment, installed solely to serve an individual applicant or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10. **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11. **Irrigation** means water pumping service.

1.12. **Limited-Income Multi-Unit Residential Housing** means multi-unit housing that primarily leases to lower income or very low-income residents as defined by the U.S. Department of Housing and Urban Development HUD Public Housing Program.

1.13. **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicant's successors in interest with Company approval, which approval will not be unreasonably withheld.

1.14. **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.15. **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.16. **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.17. **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.18. **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or

seasonal in nature. Permanency at the service location may be established by such things as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.19. **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.20. **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.21. **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.

1.22. **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.23. **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.24. **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.25. **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed

1.26. **Arizona Rural Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.27. **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Arizona Rural Municipality, and where the Arizona Rural Municipality will be the lease-holder for future permanent applicants.

1.28. **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.29. **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.30. **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

~~1.30.~~1.31. **Voltage** for purposes of APS rates, secondary voltage is considered 600v and below. Primary is considered 601v up to 69kv. Transmission is 69kv and above. For clearances or engineering purposes refer to APS's Electric Service Requirements

Manual.

2. General Provisions for Service

2.1. **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), Temporary Applicants (Section 13), and Doubtful Permanency Customers (Section 14).

2.2. **Schedule of Charges** - An applicant requesting an extension will be provided a sketch showing the Extension Facilities and a~~n itemized cost~~ quote based on the Schedule of Charges or other applicable details. ~~The Schedule of Charges is attached to this Service Schedule as Attachment 1.~~ When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Subdivisions 100 lots or greater or that require feeder, backbone and/or major infrastructure to serve development~~Extension Facilities for General Service applicants with estimated demand loads of three megawatts or greater, or that require in aggregate 3,000 kVA of transformer capacity or greater~~.

(D) Extension Facilities for General Service applicants that require feeder, backbone and/or major infrastructure or specialized equipment to serve project~~that require three-phase transformer installations greater than the sizes noted in the Schedule of Charges~~.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments, Residential Lot Sale, Corporate Business and Industrial Park Developments, or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.

2.3. **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all ~~earth work~~earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

(C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

(D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

2.4. **Refunds** – The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) The Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High-Rise Development will be five years from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family

Developments will be five years and will start three months from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

2.5. **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6. **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1. Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on an allowance ~~free footage basis~~ under the following conditions:

(A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site plan has been approved and recorded in the county having jurisdiction.

~~(C) The total footage of the Extension Facilities (primary, secondary, service) does not exceed 750 feet per applicant or $10,000; or~~

~~(D)~~(C) The total cost of the Extension Facilities (primary, secondary, service), as determined by Company, is less than $10,000 per applicant.

3.2. All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3. Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5. The ~~footage allowance of 750 feet and~~allowance ~~the~~ cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

~~3.6. Examples of the application of Section 3.1 can be found in Attachment 2 – Free Footage Illustrative Example.~~

4. Residential Subdivision Developments

4.1. Extension Facilities will be installed to Residential Subdivision developments of four or more homes in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If the final approved plat is different from what was originally submitted to the Company, it may cause delays and additional cost for redesign.

4.2. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition or organizational structure of developer.

4.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights.

4.6. The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date the Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7. Examples of the application of Section 4 can be found in Attachment ~~3~~ 1 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1. Extension Facilities will be installed to residential "Lot Sale" developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

~~(A)~~(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2. ~~The development plat has been approved and recorded in the county having jurisdiction.~~ The cost of extending service to applicant will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost Estimate ~~depending on the scope of the project~~.

5.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

5.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan

5.5. Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1. Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2. The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate ~~based on the scope of the project~~.

6.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

6.4. Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

7.1. Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2. The cost of extending service to applicant will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost estimate ~~depending on the scope of the project~~.

7.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition, or organizational structure of applicant.

7.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights etc.

7.6. The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8. General Service Provisions

8.1. Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9. Basic General Service

9.1. Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2. The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3. The cost for Extension Facilities that require feeder, backbone, major infrastructure, or specialized equipment to serve the project~~installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity~~, will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost Estimate ~~depending on the scope of the project~~.

~~9.4. The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project Specific Cost Estimates.~~

~~9.5.~~9.4. Economic Feasibility Analysis for Basic General Service Applicants - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an

adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(E) Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(F) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10. High Rise Developments

10.1. Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS' Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

10.3. Economic Feasibility Analysis for High Rise Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to

advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4. Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

11. Mixed-Use Developments

11.1. Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

11.3. Economic Feasibility Analysis for Mixed Use Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4. Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12. Corporate Business & Industrial Park Developments

12.1. Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2. The cost of installing Extension Facilities will be determined in accordance with ~~the Schedule of Charges,~~ a Project-Specific Cost Estimate~~, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project~~.

~~12.3. The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project Specific Cost Estimate depending on the scope of the project.~~

~~12.4. The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project Specific Cost Estimates.~~

~~12.5.~~12.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

~~12.6.~~12.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

~~12.7.~~12.5. Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13. Temporary Applicants

13.1. Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be

determined by Company based on a Project-Specific Cost Estimate.

13.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3. When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14. Doubtful Permanency Customers

14.1. When, in the opinion of Company, permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with ~~the Schedule of Charges or combination of Schedule of Charges and~~ a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for ~~street lights~~streetlights and other non-standard construction charges.

14.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15. Municipalities and Other Governmental Agencies

15.1. Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2. The effective date for projects enacted under this provision for purposes of Section 2.4 will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16. Change in Applicant's Service Requirements

16.1. Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or

combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17. Relocations, Conversions and Upgrades of Company Facilities

17.1. **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2. **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3. **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

18. Additional Primary Feed or Specialized Equipment

18.1. When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate.

Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19. Unusual Circumstances

19.1. In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20. Abnormal Loads

20.1. Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21. Master Metering

21.1. **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion is individually metered by Company.

21.2. **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable under the following conditions:

(A) For Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care or;

(B) For Limited-Income Multi-Unit Residential Housing that uses solar power in a "behind-the-meter" application

21.3. **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4. **Conversion from master meter to individually metered system** - Company will convert its facilities from a master metered system to a permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22. Voltage

22.1. All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2. Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.

23. Point of Delivery

23.1. For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

23.2. For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.

23.3. For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

24. Easements

24.1. Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension will be obtained by applicant and provided to Company in Company's name without cost to or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25. Grade Modifications

25.1. If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26. Measurement and Location

26.1. Measurement must be along the proposed route of construction.
26.2. Construction will be on public streets, roadways, highways, or easements acceptable to Company.
26.3. The Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27. Agreements

27.1. **Study and Design Agreements** - Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.
27.2. **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be

credited to the cost of the extension; otherwise, the payment will be non-refundable.

27.3. **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28. Applicant Construction of Company Distribution Facilities

28.1. Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2. This option is not available for the following:

(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.

(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3. All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4. Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5. Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6. A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7. For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8. Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29. Settlement of Disputes

29.1. Any dispute between the applicant or prospective applicant and the Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30. Policy Exceptions

30.1. This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission.

(A) The following exceptions have been approved for Rural Municipality applicants:

i. Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by permanent applicants.

ii. The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

iii. The refund eligibility period for Rural Municipal Business Developments will be 7 years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

iv. Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the 7th year refundable period. Any unrefunded advance balance paid at the start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement.

v. Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

vi. The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports

the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

vii. Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

(B) The following exceptions for sections 3, 7, 9, 10, and 11 have been approved for Hopi and Navajo applicants for the extension of electric service to residential and commercial buildings within the Navajo Nation and the Hopi Reservation that are in the APS service territory.

i. APS distribution facilities will be extended up to 2,000 feet at no cost to such applicants.

ii. Applicants requiring distribution facilities extending more than 2,000 feet will pay the amount as calculated through the schedule of charges or project specific costs for any distribution facilities after the initial 2,000 feet from existing APS distribution consistent with the application sections of this schedule.

SCHEDULE OF CHARGES

Description	Rate	Unit
Single Family Underground	$ 8.40	Per foot
Single Family Overhead	$ 22.40	Per foot
Residential Subdivision*	$ 12.26	Per foot
General Service and Commercial, Single Phase, Underground	$ 16.06	Per foot
General Service and Commercial, Single Phase, Overhead	$ 28.12	Per foot
General Service and Commercial, Three Phase, Underground	$ 42.81	Per foot
General Service and Commercial, Three Phase, Overhead	$ 59.04	Per foot
Single Phase Pole Interset (pole set in existing line)	$ 7,133.39	Each
Three Phase Pole Interset (pole set in existing line)	$ 9,378.39	Each
*Residential Subdivision projects with 100 or more lots will be determined via project specific costs.		

~~Attachment 1~~

~~Schedule of Charges – Single Phase~~

~~APS Schedule 3 Rev 15, Line Extension Schedule of Charges~~

Single Phase	OH Primary	UG Primary			OH Secondary	UG Secondary	
	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Junction Cabinet	OH/UG Transition	Secondary Pole	OH/UG Secondary Transition	J Box
	$18.74	$6.12	$920	$4,242	$883	$2,607	$1,397	$131.00
	Each Installation							
Pole Interset	$10,430.00							
OVERHEAD Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$3,475	$5.93				
	200 Amp	50kVA	$4,004	$7.88				
	400 Amp	50kVA	$4,004	$7.88				
	600 Amp	75kVA	$4,945	$13.22				
	800 Amp	100kVA	$6,010	$18.57				
UNDERGROUND Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$4,099	$5.19				
	200 Amp	50kVA	$4,526	$6.82				
	400 Amp	50kVA	$4,526	$6.82				
	600 Amp	75kVA	$5,164	$13.79				
	800 Amp	100kVA	$5,962	$15.71				

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine
3) Pad Mount Junction Cabinet is a single phase termination cabinet.
4) Primary OH cost per foot is for one phase and a neutral or two phases and no neutral; includes poles, framing, 2R conductor.
5) Charges for services are based on linear footage from Transformer to SES regardless of the number of sets. J Boxes not included in footage cost.
6) All footages to be calculated by linear footages.
7) Transition is from the OH line to the UG line; includes wire down pole and accessories. Pole NOT included.

~~APS Schedule 3 Rev 15, Line Extension Schedule of Charges~~

~~Attachment 1~~

~~Schedule of Charges – Three Phase~~

	Overhead				Underground					
	Cost per Circuit Foot	Cost per Circuit Foot (3-750)	Pull Box (3-750)	Manhole (3-750)	Cost per Circuit Foot (6-750)	Pull Box (6-750)	Manhole (6-750)	Pad Mount Switch Gear	Cost per Circuit Foot 1100A Cable (3-1100)	Cost per Circuit Foot 1100A Cable (6-
FEEDER Three Phase	$32.74	$28.25	$4,472	$14,391	$55.72	$7,898	$20,077	$21964	$32.28	$63.80
		Each Installation			Each Installation				Each Installation	Each Installation
OH/UG Transition		$7,079			$8,549				$7,129	$8,649
		Each Installation								
Pole Interset	$11,352									
	Overhead		Underground							
PRIMARY Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (3-1/0T)	Cost per Circuit Foot (3-4/0T)	Pull Box	Pad Mount Switch Gear					
	$24.38	$18.20	$22.41	$1,676	$21,964					
		Each Installation	Each Installation							
OH/UG Transition		$3,133	$3,259							
		Each Installation								
Pole Interset	$11,352									

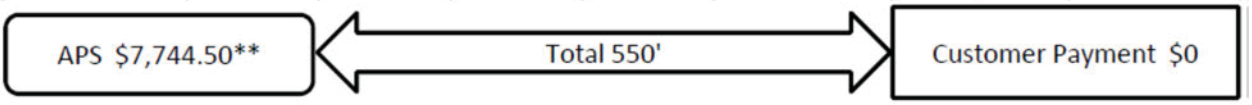
Overhead										
SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft		
200 Amp	3-25kVA	$8,774		$6.21	200 Amp	3-50kVA	$12,239		$6.21	
200 Amp	3-50kVA	$10,361		$6.21						
400 Amp	3-50kVA	$10,361		$8.40	400 Amp	3-75kVA	$14,423		$8.40	
600 Amp	3-50kVA	$10,361		$11.33	600 Amp	3-100kVA	$16,454		$11.33	
800/1000 Amp	3-75kVA	$13,166		$22.82	600 Amp	3-167kVA	$18,908		$22.82	
Underground Pad mount										Transition
SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft		OH/UG Secondary Transition
200 Amp	112.5kVA	$7,555		$7.51	200 Amp	112.5kVA	$11296		$7.51	
					400 Amp	150kVA	$12,365		$13.71	
400 Amp	112.5kVA	$7,555		$13.71	400 Amp	225kVA	$12,518		$13.71	$882.69
600 Amp	150kVA	$12,726		$19.81	600 Amp	300kVA	$15,383		$23.08	
800 Amp	225kVA	$14,259		$39.59	800 Amp	500kVA	$11051		$39.59	
1000 Amp	225kVA	$14,259		$39.59	1000 Amp	500kVA	$11051		$39.59	
1200 Amp	300kVA	$15,603		$39.59	1200 Amp	750kVA	$22,243		$59.27	
1600 Amp	500kVA	$20,538		$79.04	1600 Amp	1000kVA	$25,957		$79.04	
2000 Amp	500kVA	$20,544		$79.04	2000 Amp	1000kVA	$25,963		$79.04	
2500 Amp	750kVA	$28,626		$138.35	2500 Amp	1500kVA	$38,007		$118.60	
3000 Amp	750kVA	$28,638		$138.35	3000 Amp	1500kVA	$31,019		$118.60	
3000 Amp	1000kVA	$33,843		$177.80	3000 Amp	2000kVA	$46,244		$177.80	

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will le summed to determine charges.
3) For Multiple services out of one three phase transformer; the service cost will be determined by each SES and the transformer cost will be determined from the combined total of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000 amps.
4) Overhead feeder cost per foot is for 3/0 and above, including 477 & 795 conductors.
5) UG Primary circuit footage is 3 cables making up 3 phase; 2 circuits is parallel conductors.
6) Charges for services are based on linear footage from transformer to SES regardless for the number of sets.
7) Transition is from the OH line to the UG line: includes wire down pole and accessories. Pole NOT included.

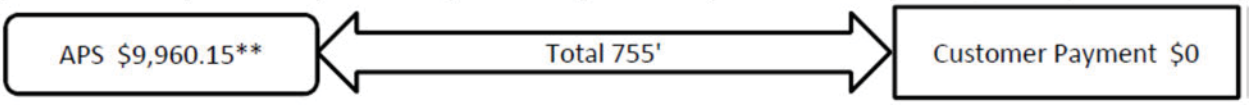
~~Attachment 2~~

~~Examples to Section 3* Free Footage Illustrative Example~~

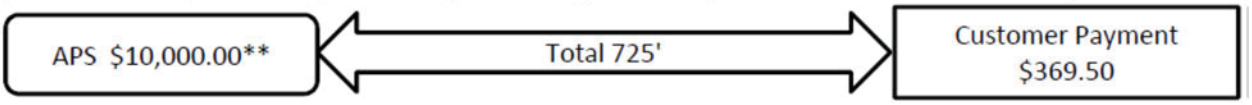
	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 1	**500**	**$15.00**	**50**	**$ 4.89**	**550**	**$ 7,744.50**	**$ -**



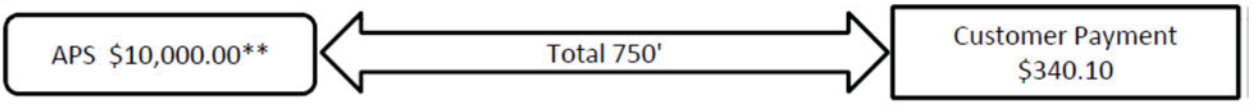
	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 2	**620**	**$ 15.00**	**135**	**$ 4.89**	**755**	**$ 9,960.15**	**$ -**



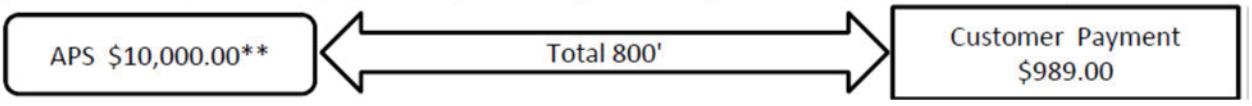
	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 3	**675**	**$ 15.00**	**50**	**$ 4.89**	**725**	**$ 10,369.50**	**$ 369.50**



	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 4	**660**	**$ 15.00**	**90**	**$ 4.89**	**750**	**$ 10,340.10**	**$ 340.10**



	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 5	**700**	**$ 15.00**	**100**	**$ 4.89**	**800**	**$ 10,989.00**	**$ 989.00**



~~*Scenarios do not reflect all components required for a complete project. **APS portion does not include cost of transformer.~~

Attachment ~~3~~1

Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

SERVICE SCHEDULE 4
TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

General Description

As outlined in this schedule, Arizona Public Service Company (APS or Company) Customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SES) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering.

1. **Definitions**
   - 1.1 **Totalized Metering** is the measurement, for billing purposes, through one meter, and on the appropriate rate, of the simultaneous demands and energy of a Customer who receives electric service at a single site, through more than one SES.
     - (A) **Adjacent -** located in a continuous enclosure or in enclosures located within 10 feet of each other and operated as one integral unit under the same name and as part of the same business.
     - (B) **Remote -** located in enclosures separated by more than 10 feet that are contiguous sites not separated by private or public property or right-of-way and operated as one integral unit under the same name and as part of the same business.
   - 1.2 **Virtual Totalizing -** Where APS is not able to meter an Adjacent or Remote totalized installation from a single meter, typically due to metering technology not being available, APS may offer to virtually meter the Customer's site.

2. **Totalized Metering Qualifications** – in order to qualify for Totalized Metering, either Adjacent or Remote, the Customer must meet conditions 2.1 through 2.8:
   - 2.1 The Customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in APS's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 9.3); and
   - 2.2 Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and
   - 2.3 Three phase and single phase service entrance sections cannot be combined for totalizing purposes; and
   - 2.4 For Standard Offer Customers, totalized metering may be accomplished by providing electronically totalized demand and energy reads or by means of a physical wire interconnection of metering information with the Customer providing conduit between the SES; for Direct Access Customers the Customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with APS's Schedule 10, Terms and Conditions for Direct Access; and

2.5 The Customer will provide vault or transformer space, which meets APS specifications, on the Customer's property at no cost to APS; and

2.6 If the Customer operates an electric generation unit on the premises, totalized metering will be permitted when the Customer complies with all of APS's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected Customer owned generation; and

2.7 Written approval by APS's authorized representative is required before totalized metering may be implemented; and

2.8 Customers electing to have accounts either Adjacent or Remote Totalized metered will be required to maintain the accounts in the approved totalized configuration for a minimum of one year.

3. **Adjacent Totalized Metering Qualifications** - In addition to the Totalized Metering qualifications listed in Section 2, the following conditions (3.1 - 3.3) must also be met in order to qualify for Adjacent Totalized Metering:

3.1 The Customer's total load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

3.2 Load must be split and served from multiple SES; and

3.3 The Customer must locate SES to be totalized within 10 feet of each other.

4. **Remote Totalized Metering Qualifications** - In addition to the Totalized Metering qualifications listed in section 2, the following conditions (4.1 - 4.4) must also be met in order to qualify for Remote Totalized Metering:

4.1 Multiple SES are separated from one another by more than 10 feet; and

4.2 Each of the Customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

4.3 The Customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

4.4 The Customer has made a non-refundable contribution for the net additional cost to APS of the meter totalizing connection and equipment.

5. **Additional Charges**

5.1 There will be no additional charge to the Customer's monthly bill for Adjacent Totalized Metering.

5.2 When the total capital investment by APS to provide service at multiple points of delivery, as computed by APS, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge will be made to the Customer

receiving Remote Totalized Metering. However, lower capital investment which results from the Customer's contribution, other than the meter costs in 4.4 above, will not be considered.

5.3 For Customers where the total capital investment by APS to provide service at multiple points of delivery, as computed by APS, is greater than the cost to serve at a single point of delivery, then there will be an additional charge. The additional monthly charge for each delivery point above one will consist of 1% of the totalized bill, plus $500.00, plus applicable taxes and adjustments.

6. **Removal of Totalized Metering Configuration**

6.1 In some cases, it may be to the Customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

(A) The Customer must submit a written request to APS stating the reason for the removal and the specific equipment to be removed.

(B) After removal of the equipment, the Customer may not ask for services to be totalized for one year from the removal date. At the end of one year, if the Customer does request services to be totalized, the applicable conditions listed above must be met.

(C) The Customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

6.2 In the event the Customer should elect to remove a meter from a totalized metering configuration, the Customer will continue to be responsible for the minimum billing kW parameters noted on the Customer's Electric Supply Agreement.

6.3 Customer may elect an alternate rate schedule for accounts that are removed from the totalized configuration; however, no further rate schedule changes may be made within the succeeding 12-month period in accordance with provisions of APS's Schedule 1.

7. **Miscellaneous**

7.1 For public elementary and secondary schools (K-12) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SES), the sizing limitation outlined in 3.1, 3.2, 4.2, and 4.3 of this Schedule will not apply for the purpose of totalized metering qualification. School customers may elect General Service (E-32), Time-of-Use General Service, and GS-Schools Time-of-Use rate schedules for the totalized configuration.

General Conditions

Arizona Public Service Company (APS or Company) will have no liability of obligation for claims arising out of the procedures for curtailment or interruption of electric service implemented in accordance with these guidelines or any future supplemental, amendatory or implementary guidelines or regulations established by law.

Company will endeavor to identify Customer(s) who might be classified as having either Essential or Critical loads. In the event that a Customer is dissatisfied with APS's classification of their load, the Customer may bring the matter to APS or the Arizona Corporation Commission (ACC) and request a different classification. Until a redetermination is made by APS or the ACC, the Customer's original classification for purposes of electric curtailment under this Schedule will be unaffected.

As circumstances permit, and as further discussed in APS's Electric Load Curtailment Plan, Company will endeavor to notify County emergency personnel or similar local authorities of existing or developing situations involving the curtailment or interruption of APS Customers.

1. Definitions

1.1 **Essential Loads** – Loads necessary to serve facilities used to protect the health and safety of the public, such as hospitals, 911 Centers, national defense installations, sewage facilities and domestic water facilities. Loads necessary to serve 911 Centers, police stations, and fire stations, which do not have independent back-up generation and require APS's electric service for operation of essential emergency equipment.

1.2 **Critical Loads** – That portion of the electric load of nonresidential Customers, which in the event of 100 percent curtailment of service, would cause excessive damage to equipment or material being processed, or where the interruption would create grave hazards to employees or the public.

1.3 **Major Use Customers/Others (With Notice)** – Those Customers having relatively large loads (over 1000 kW) or a substantial number of employees or other special circumstances that make it appropriate to schedule blackouts or curtailments differently than typical Customers. Customers who qualify as Major Use/Others (With Notice) can take 100 percent curtailment when sufficient notice is provided. These loads will be interrupted after the required notification period. "Sufficient", "required", and "appropriate" notice is that notice that APS, after consultation with the affected Customer, has determined will allow the Customer to curtail in a safe and efficient manner. The notice necessarily will vary from Customer to Customer.

1.4 **Others (With or Without Notice)** – All Customers not meeting the above definitions. These Customers will be interrupted (with or without notice) if voluntary curtailment measures are not sufficient to alleviate the situation.

2. Applicable Guidelines - For interruption or curtailment of electric service due to power supply interruptions, fuel shortage, or transmission emergency. (Also see Arizona Administrative Code R14-2-208(E), Provision of Service.)

2.1 Regulatory reliability requirements that may cause APS to shed firm customer load may include the following:
(A) Capacity and Energy Emergency (EOP-002-3.1)
(B) Disturbance Control Performance (BAL-002-1)
(C) To relieve or prevent an SOL or IROL Exceedance (PEAK SOL Methodology Guideline, (TOP-008-1)
(D) To Prevent Voltage Collapse (VAR-001-3)

2.2 In the event firm Customer load shed becomes necessary it will be done using the following method:
(A) Circuits not classified with "Essential", "Critical", or "Major Use Customers/Others (with Notice)" Customers will be interrupted on a rotating basis. The frequency and duration of the interruptions will depend on the magnitude and nature of the power shortage. The frequency and duration of interruptions will also consider the circumstances of Major Use Customers.
(B) Accurate records will be kept to ensure that these circuits are rotated in an equitable and technically feasible manner.
(C) Circuits classified as "Major Use/Others (with Notice)" will be interrupted upon the giving of appropriate notice.
(D) Customers on circuits which serve critical loads will be required to curtail the non-critical portion of their loads. Thereafter, circuits that serve critical loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as critical may be curtailed if they possess back-up generation sufficient to meet their entire load requirement. If a Customer having a critical load refuses or fails to curtail their electric consumption down to the critical load, they will not be considered to have a critical load for purposes of this Schedule.
(E) Circuits which serve essential loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as essential may be curtailed if they possess back-up generation sufficient to meet their entire load requirement.

2.3 Sudden Shortages of Power - In the event that time does not allow for the implementation of the Electric Curtailment Guidelines, Company may resort to its emergency operations procedures, with or without notice.

2.4 Automatic Load Shedding - In the event that there is a major electrical disturbance threatening the interconnected Southwest system with blackout conditions, emergency devices such as under frequency load shedding, transfer tripping, etc., will be utilized to maintain the optimum system stability.

3. **Electric Curtailment of Firm Wholesale Customers**

3.1 The term "firm wholesale Customer" will be defined as those APS Customers who purchase, on a firm basis, electricity from APS for purposes of resale.

3.2 In any given instance where a curtailment of wholesale power deliveries is involved, and subject to any required approvals of the Federal Energy Regulatory Commission or contractual provisions to the contrary, Company shall notify its firm wholesale Customers, requesting that they curtail electric service to their retail Customers during the period that Company's system is affected by power shortages. In the event that Company is unable to obtain the cooperation of a firm wholesale Customer, it may seek an order from appropriate governmental authority requiring the firm wholesale Customer to accept a reduction of electricity deliveries proportionate to the curtailment being effected on Company's system.

4. Electric Load Curtailment Plan

4.1 A detailed Electric Load Curtailment Plan will be kept on file with the ACC. This plan will contain specific procedures for implementation of the above, along with the names and telephone numbers of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. The plan will be updated at least annually and become effective upon submission to the ACC.

4.2 APS will contact the Director, ACC Utilities Division, or their designee, as soon as practical for any curtailment or interruption of APS Customers under this Schedule 5.

SERVICE SCHEDULE 6
INTERCONNECTION STUDY SERVICES AND FEES FOR NON-FERC GENERATION FACILITIES

General Description

This Service Schedule applies to any entity (Applicant) requesting to interconnect a generating facility, which is not otherwise subject to the Federal Energy Regulatory Commission (FERC) interconnection processes or rules, to Arizona Public Service Company's (APS or Company) power delivery system. *See* 18 C.F.R. § 292.306; *Western Massachusetts Electric Co.*, 61 FERC ¶61,182 at p. 61,661-62 (1992), *aff'd* 165 F.3d 922, 926 (D.C. Cir. 1999).

All services described in this Schedule are distinct from any similar-termed services provided by APS under FERC interconnection processes, which are not governed by this Schedule.

The construction or installation of interconnection facilities will be completed in accordance with the provisions of a separate agreement or contract.

1. Applicability

1.1 This schedule will only apply to:

(A) third-party-owned generation, a Qualifying Facility as defined in 18 C.F.R. § 292.203, for which the total generation output that is transmitted to the APS power delivery system is sold directly to APS; or

(B) APS-owned generation, generation that otherwise would meet the requirements in 18 C.F.R. § 292.203.

1.2 This Schedule will not apply to a generating facility that is interconnected at less than 1MW on the load side of an APS retail Customer's meter and is primarily intended to serve the Customer's electricity requirements, including, for example, a net metering facility as defined in A.A.C. R14-2-2302.

2. Study Services and Fees

2.1 Feasibility Studies - APS will conduct a preliminary review of the potential impacts of the proposed generating facility on the APS power delivery system. The study will assess the expected capacity requirements of the proposed generator on the delivery system compared with the available system capacity at the point of interconnection and identify any potential overload issues for the delivery system and circuit protection devices. Additionally, this study will provide an initial assessment of the complexity and likely costs for the interconnection.

(A) The Applicant will identify the proposed project site location before start of the study.
(B) Although the Feasibility Study is optional, no system impact or cost information will be provided by APS without the study and associated fee.
(C) The study fee for Interconnections below 69 kV is $5,000 per study (non-refundable).
(D) For Interconnections 69 kV and above, Applicant will pay APS's actual cost of performing the study.

2.2 System Impact Studies - APS will conduct a full technical review of the project's impact on the APS power delivery system, including power flow, stability analysis (69 kV and above only), APS system protective device coordination, system protection schemes and voltage drop. This study will determine if any upgrades to APS's system are required to build and interconnect the project as designed.
(A) The study fee for Interconnections below 69 kV is $15,000 per study. Fee will be reduced to $10,000 if a Feasibility Study has been completed by APS for the specific project (non-refundable).
(B) Applicant will pay APS's actual cost of performing study for Interconnections 69 kV and above.
(C) Although the System Impact Study is optional, no related information will be provided by APS without the study and fee.

2.3 Facilities Studies - APS will conduct a comprehensive analysis of the actual construction requirements for the APS power delivery system, based on the information from the Feasibility Study and System Impact Study or equivalent information provided by the Applicant or third party. The study will provide the detailed costs of construction and milestones associated with the requirements.
(A) This study is required for interconnection to the APS's power delivery system.
(B) Applicant will pay APS~~'s~~ the actual cost of performing the Facility study.

3 Payment of Study Fees

3.1 For Interconnections below 69 kV, study fees will be due before the start of the study.

3.2 For Interconnections 69 kV and above, Applicant will pay APS a $20,000 deposit before the start of a Feasibility Study or a $40,000 deposit before the start of a System Impact Study. At the completion of a study the Applicant will pay APS any remaining fees above the deposit or APS will refund any excess deposit amount.

3.3 Before the start of a Facilities Study, Applicant will pay APS a $55,000 deposit. At the completion of the study the Applicant will pay any remaining fees above the deposit or will be refunded any excess deposit amount.

General Description

This Schedule establishes Arizona Public Service Company's (APS) meter maintenance and testing program for electric meters. APS will file an annual report with the Arizona Corporation Commission (ACC) summarizing the results of its meter maintenance and testing program.

1. Plan

1.1 Single-Phase and Three-Phase Self-Contained Meters - Solid State

APS will monitor performance of these types of meters through the Company's Metering and Billing systems.

1.2 Single-Phase Self-Contained Meters - Non-Solid State, Electro-Mechanical and Hybrid

(A) Based on ANSI C12.1 – 2008, meters will be grouped by common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four.

(B) Analysis of the test results for each group evaluated will be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 2008 Formulas B-3, Tables A-1, A-2 and B-5. When possible, the minimum sample size will be 100 meters.

1.3 Three-Phase Self-Contained Meters - Non-Solid State, Electro-Mechanical and Hybrid

APS will monitor installations of the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

(A) Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

(B) Three-phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.

(C) Three-phase lagged-demand meters: 8 years.

1.4 Transformer-Rated Meter Installations

APS will conduct inspections and accuracy testing for transformer-rated meter installations and the associated equipment according to the following schedule:

(A) Installations with less than 500 kW: APS will monitor performance of these types of meters through the Company's Metering and Billing systems.

(B) Installations with 500 to 1,000 kW loads: 4 years

(C) Installations with 1,001 kW to 2,000 kW loads: 2 years

(D) Installations over 2,000 kW loads: 1 year

Arizona Public Service Company (APS or Company) regularly encounters situations where a complete and valid meter read cannot be obtained. In such cases the customer's usage information must be estimated in order to render a bill. This schedule describes the circumstances, methods and procedures for estimating a customer's bill and is considered a part of all rate schedules.

1. GENERAL PROVISIONS

1.1 Causes that may result in an estimated bill include but are not limited to:

(A) Weather conditions that hinder meter access or compromise employee safety;

(B) Lack of access to the meter or the site;

(C) Malfunction of the meter, related equipment, or the Automated Meter Infrastructure (AMI) system;

(D) Labor limitations due to unforeseen illness, natural disasters, or other extreme events;

(E) Meter tampering or energy diversion;

(F) Inability to transfer meter data for billing.

1.2 The following are conditions under which a bill is not considered to be an estimate:

(A) Rate changes in the middle of the billing cycle when a valid read is available;

(B) Meter information obtained from a visual meter read rather than an electronic meter reading device;

(C) Direct access service using load profiles rather than meter data;

(D) A misread meter or estimated bill that is subsequently corrected with actual data. The rebill is considered a corrected bill.

2. ESTIMATION METHODS

APS will estimate the customer's billing information, such as monthly kWh consumption, monthly kW demand, on-peak kWh, and other information using the following methods:

2.1 The estimation procedure will start with the first method and proceed to a subsequent method if necessary – for example, if the required information is not available, is unreasonable, or was also estimated.

2.2 Under each method, available kWh data is used to determine a per-day usage value by dividing the total kWh by the number of days in the billing period. The per-day usage is then multiplied by the number of days in the current billing period to determine estimates for total and on-peak kWh usage. For rates with a kW demand component the demand will be the actual demand read from the available data.

2.3 In certain cases, the specific estimation methods and procedures in this schedule may not be appropriate or adequate. In such cases APS will use reasonable judgment in estimating the bill.

2.4 APS is not required to ask the customer to provide a meter read before estimating the bill.

Method 1 - AMI Data

With AMI data, a monthly meter read may be missing but information for part of the month may be available through daily meter reads. If sufficient AMI data is available, typically at least 11 days of usage data, the bill will be estimated using the available AMI data.

Method 2 – Previous Year Data

The bill will be estimated using available data for the same month last year, for the same customer at the same premises.

Method 3 – Previous Month Data

The bill will be estimated using available data for the previous month, for the same customer at the same premises.

Method 4 – Class Average Data

The bill will be estimated using average data for a designated class of customers.

3. DAILY BILL ESTIMATION

3.1 For bills that are based on daily meter information, missing data will be estimated using the most recent day for which adequate information is available for the premises. Missing weekday information will be estimated with the most recent available weekday information. Missing weekend and Holiday information will be estimated with the most recent available weekend day information. If historic daily meter information is not available

for the premises, the billing determinants will be estimated using class average data.

3.2 Additional conditions for Prepay Energy Services:

(A) Company will indicate on its web portal, within 24 hours, if the daily bill has been estimated.

(B) After no more than three consecutive days of estimation Company will take appropriate action to obtain the actual meter information and attempt to remedy any meter, communication, or other factors causing the need for estimation.

(C) If estimation is still necessary after three consecutive days, the Company will make reasonable efforts to avoid estimating energy usage for more than seven consecutive days. In the unlikely event a meter read cannot be obtained within seven consecutive days, the individual customer will be handled on a case by case basis and best efforts used to reach the mutual satisfaction of Customer and Company.

(D) Company will not disconnect the customer due to a negative account balance caused by an estimated read which has not been trued up with an actual read.

4. HOURLY DATA ESTIMATION

4.1 Where billing information is derived from interval data, such as 15 minute or hourly intervals, the estimates will be derived from a standard validating, editing and estimating (VEE) process as follows:

(A) Determine the kWh to be estimated: Compute the total kWh for the relevant time period by subtracting the start read from the stop read for that period, using the most recent reads. Sum the interval data for the same period to determine the kWh for the intervals having valid data. Compute the kWh for the interval data needing estimation (X): where (X) equals the total kWh for the period minus the kWh for the intervals with valid data.

(B) Determine the reference day(s): Select a reference day (or days) to provide an estimate of the load shape for the missing interval data. The reference day shall have a load shape that resembles the time period needing estimation. Weekday load shapes will be estimated with weekday reference days, weekends with weekend reference days. Holidays will be estimated with a weekend reference day.

(C) Replace the missing interval data with the reference day interval data for the same hour or sub-hour intervals of the day.

(D) Scale the reference day interval data: Sum the kWh for the reference day interval data that replaced the missing interval data (Y). Create a scale factor by dividing the kWh for the section needing estimation (X) by (Y). Multiply each estimated interval data point in the period by the (X/Y) scale factor.

5. SPECIAL CIRCUMSTANCES

5.1 Distributed Generation

The billing information for distributed generation, such as total generator output and excess power, will be estimated with the 4 methods described in this schedule, except that an engineering estimate may also be used if the other methods are not available.

5.2 Dead or Failing Meter

If the meter is dead or failing, APS will not adjust the bill until sufficient information is available from a new meter, typically 11 days or more of data. At that time any billing adjustments will be based on either the new billing information, adjusted for the days in the billing period, or Method 2 – Previous Year Data described in Section 2, whichever is lower. If APS believes that this estimate does not reasonably reflect the customer's actual usage, the estimate may be adjusted downward. Such billing adjustments are limited to three months for residential accounts and six months for non-residential accounts (See Schedule 1, Section ~~4.3~~5).

5.3 Energy Diversion or Meter Tampering

If energy diversion or meter tampering has occurred the bill will be estimated using metered data from an auxiliary meter installed during the diversion investigation, meter information obtained after the diversion or tampering, consumption history before the diversion or tampering, or other reasonable sources of billing information as determined by Company.

5.4 Customer Supplied Meter Read

Some customers are approved to provide their own meter reads, consistent with ACC regulations. APS may estimate the bill if the customer fails to provide the read.

5.5 Meter Read Estimates Exceeding One Month

Estimates due to a malfunction of equipment that is owned or maintained by APS may exceed one month if the malfunction could not be reasonably discovered and corrected before the need for additional estimates. Estimates may also exceed one month if the equipment is owned or maintained by the customer.

6. TRUE-UPS OF PREVIOUS ESTIMATES

6.1 If a read from a previous month or day is estimated and a subsequent actual read is obtained, the following true-up will be performed.

6.2 Monthly kWh True-Up

If the current monthly kWh read is either lower than or substantially higher than the prior estimate, the kWh will be adjusted using the average kWh per day between the current read and the last valid read. The prior bill will be revised with the adjusted kWh applied to number of days in the billing period.

6.3 Daily kWh True-Up

If the current actual daily kWh read is either lower than or substantially higher than the prior estimate, the daily kWh will be adjusted using the average kWh per day between the current read and the last valid read. All prior affected daily bills will be revised with the adjusted kWh.

6.4 kW Demand True-Up

If kW demand was not reset and the current actual demand read is lower than the prior estimate, the previous billed demand will be adjusted downward to the new actual amount. The prior bill will be revised with the adjusted kW demand.

General Description

This Service Schedule provides the terms and conditions under which Arizona Public Service Company (APS or Company) may offer financial incentives to potential new commercial or industrial Customers or to existing commercial and industrial Customers who are adding significant new load.

Availability of this schedule is limited to the lesser of ~~100~~ 125 MW of new and additional load or 50 new Customers with 25 MW reserved specifically for rural projects.

The Customer must provide all requested information to the Company in order to demonstrate eligibility. The Company will evaluate all relevant information and will determine whether to offer the Customer an incentive.

Consistent with the schedule, when the Company determines that it is appropriate to offer an incentive to an eligible Customer, an agreement will be executed with the Customer. The agreement will specify the incentive and other terms where different from the Company's other Service Schedules.

APS will ~~file~~ submit each agreement, along with a complete ~~Customer~~ Characteristics Report with Commission Staff ~~as a compliance filing~~ for review. Each agreement ~~filed~~ submitted with the Commission Staff will become effective after 30 days. ~~after filing.~~

Any Customer information that the Company provides to Commission Staff on a C~~c~~onfidential basis will be returned to the Company ~~no later than~~ within 60 days. ~~after an application under this schedule is filed.~~

1. Eligibility Criteria

The Company will evaluate the following Customer characteristics prior to offering service under this schedule to determine if the Customer is eligible for a financial incentive:

1.1 Availability of Alternative Locations

(A) Incentives are available only to Customers who have not located or expanded in the Company's service area before the Commission's review of the application and who would not locate or expand in the Company's service area without this schedule's incentive.

(B) The Customer must provide the Company with evidence that additional locations, outside the Company's service area, have been considered for location or expansion. This evidence must consist of written documentation including, but not limited to, detailed quantitative analyses performed by the Customer or consultants regarding the suitability of alternative locations.

(C) Based on the information provided, the Company will determine whether the ~~c~~Customer would reasonably locate elsewhere in the absence of the incentive. If so, the Customer will be deemed to have met this requirement.

1.2 Effects on Competitors

(A) Incentives will be available to the Customer only when existing Customers in the same line of business and market are not adversely impacted by the discounted rates.

(B) The Customer must provide a detailed description of goods and services produced, the technology employed, and the market(s) the C~~c~~ustomer serves.

(C) Based on the provided information, along with knowledge of its customer base, the Company must reasonably verify that this requirement is satisfied for the Customer to be eligible for an incentive.

1.3 Customer Load Requirements

(A) To qualify for this schedule, electric requirements for a new Customer must be at least 2 MW and existing Customers must add at least 1 MW of load (the "New or Expansion Project"). To determine Customer load, APS will consider both energy purchased from the Company and any energy generated by the Customer using cogeneration or small power production facilities.

1. Notwithstanding 1.3(A), new customers locating to an Arizona Rural Municipality must be at least 1 MW to qualify.
2. Arizona Rural Municipality means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

(B) The Customer's monthly average load factor must be 55% or greater. This load factor criterion may be waived if one of the following apply:

1. The Customer's daily off-peak energy usage in kWh is greater than 50% of total monthly energy usage in kWh (off-peak hours will be defined using the applicable general service rate schedule); or
2. The Customer's new or added load is interruptible and the Customer's peak load is at least 3 MW.

(C) Loads that do not operate in the summer months of June through September will be given special consideration when determining an applicable incentive.

(D) APS will assist the Customer to consider and employ state-of-the-art, cost-effective energy conservation and demand response measures at its facility. These measures may include efficiency motors, motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.

1.4 Economic Requirements

(A) The load must be economic, as calculated under the Company's current extension policy using standard rates.

(B) To be eligible for incentives under this schedule, a potential load must bring a significant number of jobs or ancillary business into Arizona. In conjunction with this criterion, capital investment by the Cc~~e~~ustomer may also be considered.

(C) The Company will give particular consideration to Cc~~e~~ustomers whose electric bills exceed 5% of their operating expenses.

2. Conflict of Interest

2.1 In order to limit any potential conflict of interest, APS is required to submit an affidavit to Commission Staff for each Customer under consideration for service under this Service Schedule. This affidavit will include:

(A) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries, or one who has filled such role within the three-years prior to the effective date of the Customer's agreement, to the Company's knowledge, has or had any material interest, direct or indirect, in any substantial services, including real estate broker services, provided to the Customer in connection with the New or Expansion Project; and

(B) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has, or within the prior 12 months had, any direct or indirect material interest in any real property owned in whole or in part by the Customer in connection with the New or Expansion Project.

2.2 If the affidavit provided by APS is shown to be inaccurate, the Commission will, in future APS rate cases, impute as revenue the difference between the discounted rate and the tariffed rate which would otherwise apply to the Cc~~e~~ustomer for the period during which the discount was in effect.

2.3 To the extent APS cannot obtain the requested affidavit, APS may submit an affidavit to Commission Staff disclosing the nature of any such known material interests and explain why an affidavit cannot be obtained.

3. Rate Provisions

3.1 A Customer satisfying the requirements above may receive an incentive to locate in the Company's service territory. The incentive will be a discount from the Customer's otherwise applicable base electric bill (excluding taxes and adjustments).

3.2 The discounted charges will not be below the Company's marginal cost.

3.3 The discount may vary over the term of the Customer agreement.

3.4 The discount will not be larger than 25% of the Customer's total energy bill from the Company.

3.5 No discount will be provided from the minimum bill as computed under the Customer's otherwise applicable rate.

3.6 For current customers adding load, the discount will apply only to the added load.

3.7 Any incentive available under this schedule will be limited to a specific period of six years or less.

3.8 The specific discount and the period over which the discount is applied will be determined after full evaluation of the Customer information as determined by the Company.

4. ~~Customer~~ Characteristics Report

Each agreement must be accompanied by a Customer provided Characteristics Report. The following information will be included in the ~~Customer~~ Characteristics Report provided by the Customer unless otherwise noted:

4.1 General Information
(A) Customer name
(B) Customer contact—name and address
(C) Dates of C~~c~~ustomer application and Company decision
(D) New or existing C~~c~~ustomer
(E) Proposed effective date of agreement
(F) The number of direct permanent full-time jobs being created in APS service territory
(G) The average percent of County Median Wage for the direct jobs being created
(H) The anticipated capital investment to be made by the Customer

4.2 Location Decision
(A) Customer location
(B) Description of other locations considered
(C) Other locations of C~~c~~ustomer's operations

(D) An affidavit from ~~e~~Customer demonstrating that the C~~c~~ustomer would not locate or expand in Arizona absent the discounts
(E) Within ninety (90) days of the effective date of any agreement under this Schedule, the C~~c~~ustomer must supply written documentation and analyses substantiating the affidavit provided under 4.2 (D)
(F) If the requirements of 4.2 (E) are not met within ninety (90) days of approval of the agreement, the agreement will be void
(G) Proportion of C~~c~~ustomer's production and distribution expenses accounted for by electricity, by natural gas, and by other energy sources (specify)

4.3 Effects on Competitors
(A) Description of the ~~Nature of~~ business ~~– description and North American Industry Classification System (NAICS) code~~
(B) Number of other C~~c~~ustomers in same business
(C) Market area served by C~~c~~ustomer
(D) Description of effects on other C~~c~~ustomers in Arizona

4.4 Load Characteristics
(A) Size of load
(B) Annual load factor
(C) Off-peak operation
(D) Description of daily load shape
(E) Seasonality
(F) Interruptibility
(G) Permanency of load
(H) Estimated impact on system peak demand from the new load

4.5 Energy Service Mix
(A) Use of natural gas and other energy sources
(B) Description of energy efficiency measures—building design, processing, and other
(C) Feasibility of cogeneration

4.6 Rates – APS Provided
(A) Applicable rate schedule
(B) Years discount will be in effect
(C) Percentage discount by year
(D) Estimated annual revenues
(E) Estimated annual incremental electricity production costs
(F) Support that the agreement meets the terms described in Rate Provisions 3.2 and 3.4

4.7 Special Agreement Provisions – APS Provided
(A) List of special provisions
(B) Reasons for special provisions

General Description

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, et seq., referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers will obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services will remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Under the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services when permitted as specified herein.

1. General Terms

1.1 Definitions - The definitions of principal terms used in this Schedule will have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

1.1.1 Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

1.1.2 Service Account - Unless otherwise stated, all references to "Service Account" in this agreement will refer to an installed service, identified by a Universal Node Identifier (UNI).

1.1.3 Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1 Non-Discrimination

2.1.1 Company will discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission (FERC) or applicable affiliate transactions rules, Company will not:

2.1.1.1 Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2 Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2 Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1 Timeliness, Due Diligence and Security Requirements

3.1.1 ESPs will exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs will make all payments owed to Company in a timely manner.

3.1.2 ESPs will adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2 Arrangements with ESP Customers

ESPs will be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company will not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3 Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4 Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5 Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1 ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation will not be used to compute Company charges or for tariff applicability.

3.5.2 Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision will not restrict the use of separate parties for metering and billing services.

3.6 Interval Metering

3.6.1 "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand

in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company will determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7 Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company will have access to meter data necessary for regulatory purposes or rate-setting purposes under mutually agreed upon terms with the ESP for such data access.

3.8 Statistical Load Profiles

Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers will pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10 Liability In Connection With ESP Services

3.10.1 "Damages" will include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2 Company will not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory

requirements related to Direct Access service, or as otherwise set forth in Company's Schedule 1.

3.10.3 Company will not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4 Company will not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5 An ESP is not a Company agent for any purpose. Company will not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances will Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision will not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. **Customer Inquiries and Data Accessibility**

4.1 Customer Inquiries - For customers requesting information on Direct Access, Company will make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list will not be considered an endorsement or other form of recommendation by Company.

4.2 Access to Customer Usage Data -For Company customers on Standard Offer Service, Company will provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1 ESPs may request Customer usage data before submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data at rates approved by the ACC.

4.2.2 Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquiries Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services will be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services will be directed to the ESP.

4.4 Customer Inquiries Related to Emergency Situations and Outages

4.4.1 Company will be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2 Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

5. ESP Service Establishment

5.1 Before the ESP or its agents can offer Direct Access services in Company's distribution service territory they must meet the applicable provisions as listed:

5.1.1 All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2 All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3 Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5 All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1 The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2 The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3 The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4 The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when

providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6 For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing will not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7 Compliance testing will be required for a MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6. **Direct Access Service Request (DASR)**

6.1 A DASR is submitted under the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and will also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs will have a CC&N from the ACC; will have entered into an ESP Service Acquisition Agreement with Company, if required, and will have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein will be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4 A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company.

A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5 Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site.

6.6 DASRs will be handled on a first-come, first-served basis. Each request will be time and date stamped when received by Company.

6.7 Once the DASR is submitted, the following timeframes will apply:

6.7.1 Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company will provide the reasons for the rejection. If a DASR is held pending further information, it will be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2 When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1 When Company is acting as the MSP, Company will perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days before the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP will notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8 DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days before the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days before the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates will be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10 If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received will be processed in that period. All subsequent DASRs will be rejected.

6.11 Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, will be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP will be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12 Customers returning to Company Standard Offer service must contact their ESP. The ESP will be responsible for submitting the DASR on behalf of the customer.

6.13 ESPs requesting to return a Direct Access customer to Company Standard Offer service will submit a TS DASR and will be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14 Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access service. Direct Access customers returning to Company Standard Offer service may be subject to the RCDAC-1.

6.15 Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees under Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16 A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17 Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18 Company will not hold the ESP responsible for any customer unpaid billing charges before the customer's switch to Direct Access. Unpaid billing charges will not delay the processing of DASRs and will remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company will not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer will not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company will not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 Subject to availability, and under the terms in the ESP Service Acquisition Agreement, this Schedule 10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company will bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company will comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills will include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP will receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers under the terms and conditions of the applicable ACC approved tariff.

7.2.3.2 The ESP will submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and under the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1 Bills under this option will be rendered once a month. Nothing contained in this Schedule will limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2 Except as provided in Section 7.2.4.1, Company will require that all ESP and Company charges be based on the same billing period data.

7.2.4.3 ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued under this Section may also include a message that Company charges were previously billed.

7.2.4.3 ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5 Restrictions

Company UDC Consolidated Billing will be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3 ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP will be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations

7.3.2.1 Company will calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company will provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill will include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP will comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges will be handled according to ACC procedures.

7.3.3.4 The ESP will process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans will not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company will continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP will process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, will receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company will make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company will continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included under the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) will resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, will be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error will contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company will be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP will be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the

charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP will be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer will be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company will transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP will apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP will be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company will remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late

charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges under Schedule 1. If an ESP fails to pay these charges before the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing under Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP will pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges under Schedule 1. If an ESP fails to pay these charges before the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing under Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company will be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company will not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP will assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments will be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules will apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account will be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP will be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company will not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety

violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company will notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges before disconnecting electric service to the Customer. Company will further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge will be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company will reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company will notify the ESP of a Customer's reconnection.

7.9.3 Company will not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10 Involuntary Service Changes

7.10.1 A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1 The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5 The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2 Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company will initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company will provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company will notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer will have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section will not disconnect electric service provided to Customer other than as provided in Section 4.4.2.

7.10.3 Change in Service Election Absent Exigent Circumstances

7.10.3.1 In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2)

or involve an ESP's unauthorized energy use, Company will notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1 The nature of the alleged failure;

7.10.3.1.2 The actions necessary to remedy the failure;

7.10.3.1.3 The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2 The ESP will have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and will notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section will not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4 Termination of ESP Consolidated Billing

7.10.4.1 Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1 The Company will notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2 If the ESP fails to pay Company (or dispute payment under the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company will notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers will be switched to Dual Billing.

7.10.4.1.3 If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers will be switched to Dual Billing.

7.10.4.2 Upon termination of ESP Consolidated Billing under Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in

compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP under the ESP Service Acquisition Agreement.

7.10.5 Termination of Company UDC Consolidated Billing

7.10.5.1 Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6 Upon termination of ESP Direct Access services under Section 7.10, the provision of the affected service(s) will be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company will provide such services, until such time that Customer makes an election.

7.10.7 Company will not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11 ESP Security Deposits

7.11.1 Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2 The amount of the security deposit required will not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a

separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3 Security deposits required under Section 7.11 will be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company will issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4 Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit under Section 7.11

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MRSP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for all Direct Access Customers.

8.2.1.1 If the ESP subcontracts with the UDC for Meter Services they must subcontract for both Metering and Meter Reading Services. The ESP will remain responsible for all cost associated with Metering, Meter Installation, Meter Communications and other MSRP related cost. All such cost will be authorized by the ACC.

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party or the UDC. If the ESP sub-contracts any of the components of these services to a third party or UDC, the ESP will, for the purposes of this Schedule, remain responsible for the services including communication equipment, meter reading equipment and associated maintenance necessary to obtain reads from specialized meters that may be required by a Direct Access Customers.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party or UDC assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards will apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test ANSI 57.13 Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services will also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters will have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, under the Rules, meters must be compatible with Company's AMI meter reading system.

8.6.3 No meter or associated metering equipment will be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter will be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service will be processed according to the following table before its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph AMI Meters	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing will be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record will be kept as long as the meter is in service.

8.8 Meter Test Requests

Under A.A.C. R14-2-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party will be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party will reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP will take reasonable measures to detect meter error. The MSP will notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP will make any repairs or changes required to correct the error. ESPs and Company will use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent will install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter will remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment will be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days before the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent will inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers under ACC Rules and Regulations, the ESP will be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent will return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent will be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP will be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter will ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements.

Company will perform a preinstallation inspection on all new construction. Local city/county clearances may also be required before energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC will coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership will be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment will be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 If the ESP or customer owns the meter, the ESP must own the CTs, PTs, and associated equipment, except as provided in Section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from Company at depreciated original cost.

8.12.3 The following provisions apply to the ownership of CTs and PTs.

8.12.3.1 For distribution voltages up to 25kV, the ESP or Company will own the CTs and PTs. For transmission primary voltages (over 25kV), the CTs and PTs will be owned by Company. ESP owned CTs and PTs must meet Company specifications. No CTs and PTs or associated metering equipment will be set or allowed to remain in service if it is determined that the CTs and PTs or their associated equipment does not meet Company's approved specifications, as set forth in Company's Electric Service Requirements Manual in place at the time of installation.

8.12.4 All CT-rated meter installations will utilize safety test switches, and all self-contained commercial metering will utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation and associated cost. Company may optionally provide meter installation under the provisions of this Service Schedule.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents will:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they will meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP will coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company will notify the ESP immediately and the ESP will notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP will ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and will notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations will perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least 10 days before the next scheduled read date. MRSP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers will be read, validated, edited, and transferred under Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file will be posted immediately.

8.15.2 Both Company and the ESP will have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data will include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data will be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data will contain applicable reason codes under the 867 guidelines.

8.15.4 The MRSP will provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs will read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter will contain the full period from read date to the following read date. Interval data cycles will be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp will begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 will constitute the billing cycle. For meter exchanges back to Standard Offer, every interval will be included up to the last full interval before the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP will provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for All Meters

8.16.1.1 Meter clocks will be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time will be accurate.

8.16.1.3 All meter reading data will be validated under the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Under guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data will be available by 3:00 p.m. Local Arizona Time (MST) on the second, working day after the scheduled read has been completed. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP will be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Before performing MRSP services in Company's distribution service territory, or before making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP will prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer will remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server will be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in Section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it will promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents will have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party will be responsible for all related expenses.

8.18.2.3 Company will adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement under section 7.10.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision will not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

General Description

Arizona Public Service Company (APS or Company) will provide specialized metering upon Customer request, if the Customer agrees to the following conditions:

1. The Customer must contact their APS Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR meter with KYZ pulse or modem options (including associated interfaces).

2. If the Customer requests a meter with a modem option, the Customer will be required to install coil of communication cable within five feet of the meter panel location and in such a manner that will provide for ease of attachment to the meter panel by APS. The phone line must be installed before the installation of the meter and will be located in such a manner as to not impede access to the metering equipment, the interior or exterior of the metering compartment, or other utility access panels. The Customer must provide APS with a phone number and any other communication access information to the meter(s) before APS's installation of the meter(s).

3. If a Customer requests kWh pulses, APS will furnish and install a Customer pulse interface and enclosure. Connections made by the Customer to the Customer pulse interface will not impede access to metering equipment, the interior or exterior of the metering compartment, or other utility access panels.

4. The Customer will be required to make a non-refundable contribution in aid of construction to APS for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

    4.1 If a meter currently exists on the Customer site, the charge is based on APS's total equipment and installation costs for the requested specialized metering less the equipment cost of APS's existing meter.

    4.2 If a meter has not been installed on the Customer site, the charge is based on APS's total equipment and installation costs for the requested specialized metering less 100% of the Adjusted Unit Cost (AUC) cost of an APS standard meter.

    4.3 If a specialized meter is existing on a Customer's site and the Customer requests an upgrade to a different type of meter, the Customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

5. APS will not place an order for a requested meter until payment has been received from the Customer. The typical lead time for procurement of meters is six to eight weeks. Once the requested meter(s) have been received, APS will schedule the installation of the meter(s) with the Customer or a designated representative.

6. APS will retain ownership of all meters and APS installed metering equipment.

7. If a Customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests APS to remove or replace the specialized meter, the Customer will not be eligible for a refund.

8. APS will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete, or inoperable, the Customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

9. APS will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

10. Under no circumstances will the Customer stop the operation or in any way affect or interfere with the operation of the Customer pulse interface and the related output wiring. The integrity of APS's billing metering equipment within the sealed metering compartment will be maintained.

11. APS reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the Customer's demand control or other equipment. However, APS will make a good faith effort to notify the Customer before any interruption of the specialized metering circuit.

12. The possible failure or malfunction of a KYZ pulse output or interface and subsequent loss of kWh contact closures to the Customer's control equipment will in no way be deemed to invalidate or in any way impair the accuracy and readings of APS's meters in establishing the kWh and demand record for billing purposes.

13. The accuracy of the Customer's equipment is entirely the responsibility of the Customer. Should the Customer's equipment malfunction, APS will reasonably cooperate with the Customer to the extent of ensuring that no malfunction exists in APS's equipment. Work of this nature will be billed to the Customer~~,~~ unless the actual source of the malfunction is found within APS's equipment.

14. If APS provides pulse values in kWh, Customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for APS to adjust the pulse values due to changes in APS's equipment.

15. No circuit for use by the Customer will be installed from APS's billing metering potential or current transformer secondaries.

16. APS reserves the right, without assuming any liability or responsibility, to disconnect and remove the pulse delivery equipment at any time upon 30 days written notice to the Customer.

17. Upon request by APS, the Customer will make available to APS monthly load analysis information.

18. References to electric kWh pulses above will mean dry KYZ contact closures only; the Customer is required to furnish operating voltage service. KYZ contacts are rated for and will not be wetted beyond a maximum of 100 milliampere and 120 volts DC or AC rms.

19. The Customer assumes all responsibility for~~,~~ and agrees to indemnify and save APS harmless against all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by APS resulting from the furnishing of specialized metering.

20. A waiver at any time by either party, or any default of, or breach by the other party or any matter arising in connection with this service, will not be considered a waiver of any subsequent default or matter.

21. Written approval by an authorized APS representative is required before electric kWh pulses service may be implemented.